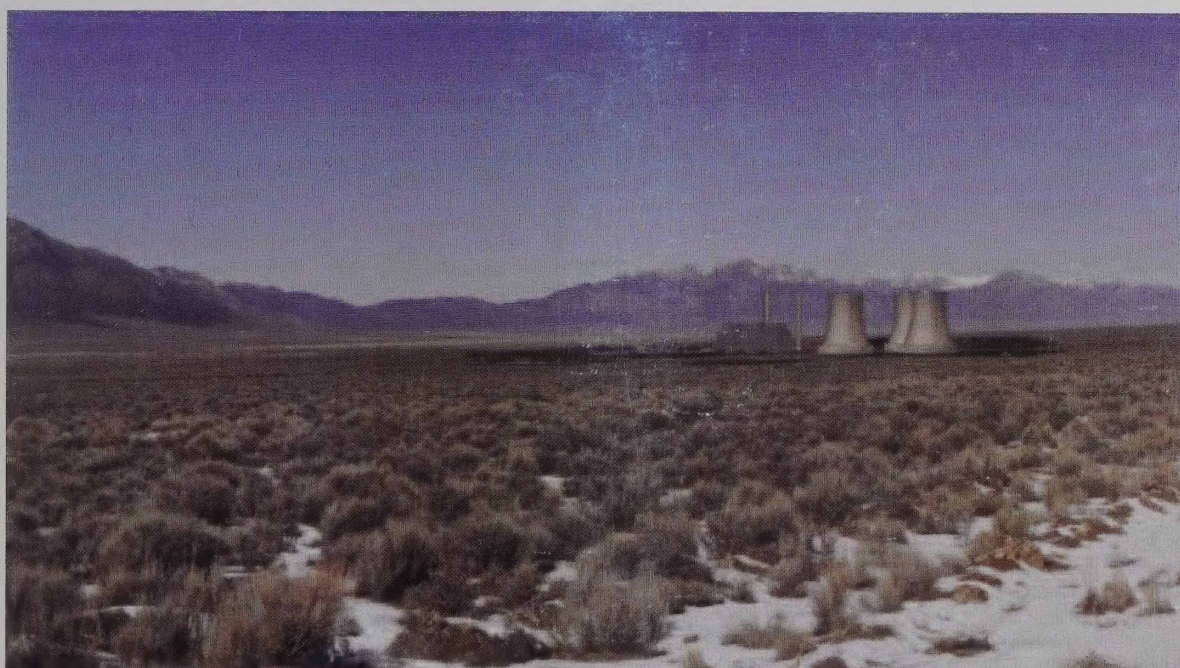
Final Environmental Impact Statement for the White Pine Energy Station Project

FES 08-38



Volume 3
Appendixes A through Q

October 2008

BLM

Ely Field Office / Nevada

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

BLM Mission Statement

The Bureau of Land Management is responsible for the stewardship of our public lands. It is committed to manage, protect, and improve these lands in a manner to serve the needs of the American people for all times.

Management is based upon the principles of multiple use and sustained yield of our nation's resources within a framework of environmental responsibility and scientific technology. These resources include recreation, rangelands, timber, minerals, watershed, fish and wildlife, wilderness, air and scenic, scientific and cultural values.

BLM/NV/EL/ES-GI-08/24+1793

BLM

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Volume 3
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U.S. DEPARTMENT OF THE INTERIOR
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Volume 3

Appendixes A through Q

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Appendix A

Development Agreement

BOOK 379 PAGE 145

NO FEE COUNTY FILE 319797
FILED FOR RECORD
AT THE [illegible]
ECONOMIC DIVERSIFICATION Council - Karen RAJALA
2004 MAR -1 PM 4:05

RECORDED IN [illegible] 379 PAGES 145-156
MARTHA VERA SINDELAR
WHITE PINE COUNTY RECORDER

319797

WHITE PINE COUNTY RECORDER'S OFFICE

DOCUMENT NO. 319797

BOOK 379 PAGE 145-156

DATE March 1, 2004

INTERIM DEVELOPMENT AGREEMENT

This Interim Development Agreement (the "Agreement") is between White Pine Energy Associates, LLC, a Delaware limited liability company ("WP Energy") and White Pine County, Nevada, a political subdivision of the State of Nevada, established pursuant to the laws of the State of Nevada ("White Pine") and is dated February 25, 2004.

RECITALS:

This Agreement is made with reference to the following facts and understandings among others:

A. WP Energy and White Pine have discussed the feasibility of WP Energy developing and constructing an electric generation power plant to be located within White Pine County with related facilities, including, without limitation, electrical transmission facilities and railroad facilities located both within and outside White Pine County (collectively referred to herein as the "Project").

B. White Pine is interested in promoting the Project in order to protect and promote the health, welfare and safety of its citizens and the citizens of the State of Nevada and to retain and promote private industry and commerce with the resultant higher level of employment and economic activity and stability.

C. WP Energy wishes to review, analyze, perform studies on and procure data on the feasibility of the Project.

D. White Pine is the owner of Permits 45834-45855, inclusive, approved by the Division of Water Resources, State Engineer, Department of Conservation and Natural Resources, State of Nevada, for the total combined annual duty of up to 25,000 acre-feet (the "Water Rights").

E. White Pine's agreement with White Pine Generating Company, LLC dated September 12, 2001 regarding the Water Rights has been terminated or otherwise expired.

F. White Pine wishes to ensure that the Water Rights remain available for a power project, whether constructed by WP Energy or any other person or entity.

G. White Pine wishes that, regardless of the nature of or the progress of the development work on the Project or the construction and operation of the Project, White Pine's ongoing commitments will not be negatively impacted.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein set forth and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound hereby the parties agree as follows:

1. Definitions. For the purposes of this Agreement, the following terms have the following meanings:

(a) "BLM FLPMA Application" means an application filed with the Bureau of Land Management under the Federal Land Policy and Management Act to patent the Project site and grant other easements required to construct and operate the Project.

(b) "PSD Permit Application" means an application to obtain a Prevention of Significant Deterioration Permit under the Federal Clean Air Act.

2. Term. The term of this Agreement shall be twenty-four (24) months from the date set forth above. WP Energy has the right to terminate the term of this Agreement pursuant to the provisions of section 9(a) below and White Pine has the right to terminate this Agreement pursuant to the terms of section 9(d) below. If the PSD Permit Application and the BLM FLPMA Application are filed within the time set forth in Section 9(d), and WP Energy has exercised reasonable diligence and effort to obtain approval of these applications, then upon written notice to White Pine, the term of this Agreement may be extended by WP Energy for a period required to obtain issuance of these permits plus one year after their issuance. Notwithstanding any other section in this Agreement or the provisions of the prior sentences of this section 2, the term of this Agreement shall not extend beyond forty-eight (48) months from the date set forth above.

3. Water Rights. During the term of this Agreement, White Pine shall not negotiate, sell, lease, license, encumber, transfer or convey the Water Rights, or any portion thereof, or contract, promise or grant an option or any other ownership interest to any person or entity to do so, or utilize the Water Rights except to WP Energy pursuant to the terms of this Agreement.

4. Roads. As requested by WP Energy and as permitted by Nevada law, White Pine shall exercise its reasonable efforts to own and maintain existing and new county roads to provide truck and car access to the site of the Project. The parties understand that the construction of any new roads for the Project or the enhancement of existing roads for the Project over and above reasonable and routine maintenance will be paid for by the Project and not by White Pine.

5. Cooperation. White Pine shall cooperate to the fullest extent possible with WP Energy in WP Energy's performance of the Development Work, and shall make available to WP Energy all studies, analyses, reports, data and materials in its possession to assist WP Energy in the Development Work. White Pine understands that economic competitiveness of the Project is critical to the Project's feasibility.

6. Employment. The Parties understand that, if developed, the Project will create temporary employment opportunities in connection with the construction of the Project, and will also create permanent employment opportunities in connection with the operation of the Project.

(a) WP Energy agrees to provide and to require its construction contractor to provide White Pine and the Employment Security Division of the State of Nevada a list of temporary employment opportunities, including a description of the necessary qualifications and other requirements for such employment, as and when such opportunities become available, and will advertise and require its construction contractor to advertise such opportunities within White Pine County in such manner as is reasonably expected to provide residents of White Pine County the opportunity to apply for and obtain such employment.

(b) WP Energy will, on or within a reasonable period of time following the commencement of construction of the Project, appoint a representative of WP Energy to act as a liaison between White Pine and the Employment Security Division of the State of Nevada so as to make available all necessary information regarding the skills and qualifications required for employment on a permanent basis in connection with the operation of the Project and to promote the development within White Pine County of a pool of qualified applicants for such permanent positions. WP Energy will work with White Pine and the Employment Security Division of the State of Nevada to promote the availability of permanent employment at the Project and to inform residents of White Pine County as to the qualifications necessary for such permanent employment, in such manner as is reasonably expected to provide residents of White Pine County the opportunity to apply for and obtain such employment.

7. Development Work. In consideration for the obligations entered into by White Pine contained in this Agreement, WP Energy shall perform at its expense the following (hereinafter referred to as the "Development Work"). WP Energy shall provide White Pine with quarterly reports of progress made on the Development Work.

(a) provide engineering, regulatory and political support to advance the development of a transmission line or lines to serve the Project;

(b) prepare and obtain regulatory approval of a modeling protocol for PSD permitting;

(c) conduct a site screening analysis and select the exact site and an alternate site, as required, for the Project;

(d) identify routes for related and supporting facilities;

(e) file with the BLM an FLPMA Application and such other necessary applications to begin the process of obtaining rights to BLM real property, including but not limited to transfers, leases, easements, rights-of-way, permits and other necessary approvals from the BLM to construct and operate the Project on BLM land within White Pine County; and

(f) establish a cost recovery account or other similar agreement with the BLM regarding the BLM's processing of the BLM FLPMA Application.

8. Permitting and Construction. After the Development Work is completed, to the extent that WP Energy decides to continue into the permitting and construction phases of the Project, in order to properly complete the Project, WP Energy will have to do the following:

(a) make formal electrical interconnection request to Sierra Pacific Power Company or other appropriate utility;

(b) undertake site engineering required for permitting the Project;

(c) prepare the PSD Permit Application;

(d) prepare, as necessary, proponent's environmental assessment for BLM to transfer or grant interests in real property and coordinate with the BLM for the BLM's National Environmental Protection Act processing of the BLM FLPMA Application;

(e) obtain all permits to construct and operate the Project and its related and supporting facilities;

(f) pay debt service for the construction of the Project paid for by municipal bonds if applicable;

(g) obtain financing to construct the Project; and

(h) construct the Project and its related facilities including the facilities necessary to put the Water Rights to beneficial use.

9. Termination.

(a) Termination by WP Energy. WP Energy may, at its sole discretion, at any time during the term of this Agreement, terminate this Agreement effective thirty (30) days after the date of a written notice to White Pine of the termination.

(b) If the Project is terminated pursuant to Section 9(a) above or Section 9(d) below WP Energy shall do the following:

(1) subject to subsection 9(c) below, transfer to White Pine all reports, analyses, permits, modeling results, data and studies created by or for WP Energy relating to the Project;

(2) for a minimum of two years, cooperate with White Pine in supplying information to and responding to questions from potential developers of the Project;

(3) quitclaim to White Pine all WP Energy's rights in and to the Water Rights including any improvements constructed associated with the Water Rights, if any;

(4) assign any real estate rights obtained by WP Energy for the Project to White Pine to the extent assignable; and

(5) restore any land disturbances to pre-Development Work or pre-construction conditions.

(c) Proprietary Data or Modeling. WP Energy has no obligation to convey to White Pine pursuant to subsection (a) above any proprietary data or modeling. The terms "proprietary data or modeling" shall mean trade secrets or confidential business information of WP Energy relating to the amount or source of any income, profits, losses or expenditures of WP Energy, any and all proprietary information which WP Energy keeps secret from competitors, including but not limited to, modeling programs which WP Energy uses, information and evaluation of its competitors and others in the energy business, projections of future loads and power or fuel supplies, projections of future prices of electric energy or other commodities, the costs of power plant equipment and construction, technologies for the construction and operation of electric plants, and any and other proprietary information which WP Energy keeps secret from competitors.

(d) Termination by White Pine. White Pine may, at its sole discretion terminate this Agreement effective thirty (30) days after the date of a written notice to WP Energy of the termination, but only if one of the following has not occurred other than because of an Uncontrollable Force as described in section 14 below:

(1) WP Energy has not submitted to the State of Nevada a proposed PSD Class II protocol within six (6) months from the date of this Agreement; or

(2) WP Energy has not filed the application beginning the BLM permit process described in Section 7(e) above by the later of (i) six (6) months from the date upon which the City of Ely and/or the White Pine Historical Railway Foundation acquires the ownership of the Nevada Northern Railway presently owned by the City of Los Angeles Department of Water & Power or (ii) one (1) year from the date of this Agreement; or

(3) WP Energy has not completed the item described in Section 7(f) above within the later of (i) six (6) months from the date upon which the City of Ely and/or the White Pine Historical Railway Foundation acquires the ownership of the Nevada Northern Railway presently owned by the City of Los Angeles Department of Water & Power or (ii) one (1) year from the date of this agreement or (iii) three (3) months after filing the application described in Section 7(e) above; or

(4) WP Energy has not filed the PSD Permit Application by the later of (i) six (6) months from the date upon which the City of Ely and/or the White Pine Historical Railway Foundation acquires the ownership of the Nevada Northern Railway presently owned by the City of Los Angeles Department of Water & Power or (ii) one (1) year from the date of this Agreement.

10. Water Rights. Title to the Water Rights shall forever remain vested in White Pine or in an agency or district created by White Pine to own, manage and use the Water Rights.

(a) Water Rights Agreement. If during the term of this Agreement WP Energy obtains a PSD Permit and BLM FLPMA Permit, White Pine and WP Energy shall enter into a lease or other water supply agreement that provides WP Energy, at no additional cost, the sole and exclusive right (i) to exercise the Water Rights and (ii) to place the Water Rights to a beneficial use at the site of the power generation plant of the Project. The lease or other water supply agreement shall have a term covering the useful life of the power plant and shall become effective upon financial closing of the Project. WP Energy shall bear all direct costs related to the construction of wells, water pipelines, pumping stations, or other facilities required to place the Water Rights to a beneficial use to be constructed and operated by either White Pine or the WP Energy. The parties agree, upon the request of WP Energy, to promptly negotiate during the term of this Agreement the specific form of the lease or other water supply agreement incorporating the provisions specified in this Section 10(a). Upon agreement of the form of the lease or other water supply agreement, the parties agree to amend this Agreement and incorporate such lease or water supply agreement as an exhibit hereto.

(b) Regulatory Filings. During the term of this Agreement, WP Energy shall file, with the cooperation and reasonable approval of White Pine or its successor, annual applications for extensions of time, proofs of completion of work, or proofs of application of water to beneficial water, as the case may be, with the Nevada State Engineer and shall pay any fees associated with such statutorily required filings. WP Energy shall obtain any and all applicable permits or waivers from the Nevada State Engineer to perform test drilling and such further analyses of the aquifer which is the source of the Water Rights as WP Energy believes are necessary. Any and all applications to change the point of diversion or place of use of any or all of the Water Rights shall be filed in the name of White Pine. The purpose of any changes to the point of diversion or place of use is to allow WP Energy, based upon sound hydrology and test drilling, to locate the most favorable sites for ground water development for the Project. White Pine agrees to allow WP Energy the right to file required documents with the Nevada State Engineer, but all such filings shall be made in the name of White Pine. White Pine agrees to either advise the Nevada State Engineer, in writing, that WP Energy has authority to file such documents; or alternatively, White Pine shall promptly ratify all of such filings.

11. Liability and Indemnity. WP Energy and White Pine shall each indemnify, defend and hold harmless the other and the other's directors, officers, commissioners, employees and agents, from and against any and all losses, damages, claims causes, of action or actions, including reasonable attorney's fees, incurred by them with respect to WP Energy's breach of its obligations under this Agreement and the performance or non-performance of the Development Work. Neither WP Energy nor White Pine, nor any of their respective directors, officers, commissioners, employees and agents, are liable to the other party for indirect, special, incidental and consequential damages, including but not limited to, loss of profits or revenues, loss of use of the Project, the cost of capital, the cost of purchase and replacement power and claims for service interruptions as a result of the performance or non-performance of the Development Work. The provisions of this section shall not be construed to relieve any insurer of its obligations to pay insurance claims in accordance with any insurance policies obtained by WP Energy or White Pine.

12. Relationship of Parties. Nothing in this Agreement shall ever be construed to create an association, joint venture, trust, partnership or other legal entity or to impose a trust or partnership covenant, obligation or liability on the parties hereto.

13. General Provisions.

(a) Severability. In the event any of the terms, covenants or conditions of this Agreement or the application of them are held invalid as to any person or circumstance by any court with proper jurisdiction, all other terms, covenants or conditions of this Agreement and their application are not affected thereby, but shall remain in force and effect unless a court holds that the provisions are not separable from all other provisions of this Agreement.

(b) Waiver. Any waiver at any time by any party of this Agreement of its rights with respect to a default or any other matter shall not be deemed a waiver with respect to any later default or matter.

(c) Counterparts. This Agreement may be executed in counterparts.

(d) Successors Bound. This Agreement shall be binding upon and shall inure to the benefit of the parties and their respective successors in interest.

(e) Assignment. This Agreement may be assigned by WP Energy to its parent corporation or any affiliate of WP Energy, and WP Energy may assign a portion of its rights and obligations under this Agreement to another party or entity only with the reasonable approval of White Pine. However, except as provided in the preceding sentence, this Agreement may not be assigned by either party without the express written consent of the other party, which consent may not be unreasonably withheld or delayed.

(f) Good Faith. The parties agree to deal fairly and in good faith at all times, and to execute and deliver such other and further instruments and documents, and take such other actions as may be necessary to fully effectuate the transactions contemplated by this Agreement, and to further the intent and purpose of this Agreement.

(g) Governing Law. The laws of the State of Nevada will govern the interpretation, validity and effect of this Agreement.

(h) Amendment of Agreement. This Agreement may only be amended by consent of both parties. Any amendments must be written and executed with the same formality as this Agreement.

(i) Entire Agreement. This Agreement constitutes the entire Agreement between the parties and there are no representations, conditions, warranties or collateral agreements (expressed or implied), statutory or otherwise, with respect to this Agreement other than is contained herein.

(j) Authority to Execute. The parties hereto represent and warrant that the person executing this Agreement on behalf of each party has full power and authority to enter into this Agreement and that the parties are authorized by law to engage in cooperative action set forth herein.

(k) Recording and Filing. A copy of the Interim Development Agreement shall be recorded in the official records of the White Pine County Recorder concurrently with the execution and delivery hereof and a copy shall also be filed with the office of the Nevada State Engineer, Carson City, Nevada, with applicable notice thereof being placed in Permits 45834-45855 inclusive.

14. Uncontrollable Forces. No party shall be considered in default in performance of any of its obligations under this Agreement when the failure of performance is due to an uncontrollable force. An "uncontrollable force" shall be any cause beyond the control of the party affected, including but not limited to, the failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightening, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, restraint by court order or public authority, an action or non-action by or inability to obtain the necessary authorizations, approvals or permits from any governmental agency or authority. Nothing contained in this Agreement shall be construed so as to require a party to settle any strike or labor dispute in which it may be involved. If any party is rendered unable to fulfill any of its obligations under this Agreement by reason of an "uncontrollable force", such party shall give prompt written notice of that fact to the other party and shall exercise due diligence to remove the inability with reasonable dispatch. In that event, the parties hereto shall diligently and expeditiously determine how they may equitably process to carry out the objectives of this Agreement. The time for the performance of the act delayed by the "uncontrollable force" shall be extended by the delay experienced due to the "uncontrollable force". However, no such delay shall affect the right of WP Energy to terminate this Agreement pursuant to section 9 above, nor shall the provisions of this section 14 extend the absolute limit of 48 months of the term of this Agreement pursuant to the last sentence of section 2 above.

15. Review by Counsel. Each party to this Agreement and its counsel have reviewed and revised this Agreement. The normal rule of construction to the effect that any ambiguities are to be resolved against the drafting party shall not be employed in the interpretation of this Agreement or any amendments to it.

16. Notices. Any notice, demand or request in connections with this Agreement shall be in writing and shall be sent by U. S. Mail, overnight express or by fax to the parties as follows:

White Pine Energy Associates, LLC
c/o LS Power Development, LLC
Two Tower Center, 20th Floor
East Brunswick, NJ 08816
Fax: 732-249-7290

White Pine County
Attn: County Clerk
P.O. Box 659
Ely, NV 89301
Fax: (775) 289-2544

with copies to:

Coordinator
White Pine County Economic Diversification Council
957 Campton St.
Ely, NV 89301
Fax: (775) 289-8860

Richard Sears, District Attorney
White Pine County
P.O. Box 240
Ely, NV 89301
Fax: (775) 289-1559

White Pine Energy Associates, LLC
c/o LS Power Development, LLC
400 Chesterfield Center, Suite 110
St. Louis, MO 63017
Fax: 636-532-2250

WHITE PINE COUNTY

By ______________________
Chairman
Board of White Pine County Commissioners

ACKNOWLEDGEMENT

STATE OF NEVADA)
)
COUNTY OF WHITE PINE)

On this day, before me, personally appeared [NAME], to me personally well known who acknowledged that he is the [TITLE] of [COUNTY], a [ ] , and that he as such officer, being duly authorized so to do, had executed the foregoing instrument for the purpose therein contained, by signing the name of the corporation by himself as such officer.

WITNESS my hand and official seal this day of 25th Feb, 2004.

Donna M Bath
~~Notary Public~~ WPCO Clerk

My Commission Expires:

____
(Seal)

WHITE PINE ENERGY ASSOCIATES, LLC

By Paul G. Thessen
Senior VP

STATE OF)
)
COUNTY OF)

On this day, before me personally appeared ~~[NAME]~~ Paul G. Thessen, to me personally well known, who acknowledged that he is the ~~[TITLE]~~ Senior VP of ~~[COMPANY]~~ White Pine Energy Associates, LLC, a ~~[STATE]~~ Delaware limited liability company, and that he as such officer, being duly authorized so to do, had executed the foregoing instrument for the purpose therein contained, by signing the name of the limited liability company by himself as such officer.

WITNESS my hand and official seal this 25th day of February, 2004.

Shonna K. Sampson
Notary Public

My Commission Expires: 9-28-04

(Seal) SHONNA K. SAMPSON
NOTARY PUBLIC • STATE of NEVADA
White Pine County • Nevada
CERTIFICATE # 92-4156-17
APPT EXP SEPT. 28, 2004

Appendix B

Water Rights Agreement

WATER SUPPLY AGREEMENT

This Water Supply Agreement ("Agreement") is entered into this 19th day of February, 2008, between White Pine County, a political subdivision of the State of Nevada (the "County"), and White Pine Energy Associates, LLC, a Delaware limited liability company ("WPEA"). The County and WPEA are referred to individually as a "Party," and collectively as the "Parties."

RECITALS

A. The County controls certain water rights (the "Water Rights") granted by the Nevada State Engineer for development and operation of an electrical power generating facility in White Pine County. The Water Rights, designated as Permits No. 72728 through 72749, inclusively, are attached as, and more particularly described in, Exhibit A.

B. The County desires to support the construction and operation of an electrical power generating facility within the County in order to provide jobs, tax revenues and other economic and social benefits to the County and its residents.

C. WPEA is actively developing a nominal 1,600 MW electrical generating facility in White Pine County, the final location of which will be specified in the BLM's Record of Decision (the "BLM ROD") for the White Pine Energy Station (the "Power Facility"). WPEA has made substantial expenditures and made substantial progress in obtaining permits, authorizations, and other prerequisites to construction and operation of the Power Facility.

D. The Parties entered into an Interim Development Agreement dated February 25, 2004, as extended by written notice on February 1, 2006, (the "Interim Agreement") that addresses, among other things, the use of the Water Rights for the Power Facility. In the Interim Agreement, the County agreed to enter into a lease or other water supply agreement pursuant in which the Water Rights would be committed exclusively to WPEA for development and operation of the Power Facility.

E. WPEA is designing and permitting the Power Facility mindful of water resources and has reduced its maximum water usage as a result of input from the public, governmental agencies and other stakeholders. WPEA intends to utilize up to 5,000 acre-feet annually to support the construction, operation and maintenance of the Power Facility as currently designed and permitted. The number and location of the points of diversion to support the Power Facility will not be known with certainty until such time that final, unappealable permits have been issued for the Power Facility including but not limited to the BLM ROD.

F. WPEA has entered into a Memorandum of Understanding with the State of Nevada to implement additional technology to capture and sequester carbon when this technology becomes technically feasible and commercially viable for the Power Facility. While the design and operation of this future technology is unknown, current research and pilot projects indicate that this

technology will require additional water for cooling purposes. Based on available information, WPEA needs to reserve an additional 5,000 acre-ft per year of water for this future technology or for other future technologies that may be implemented at the Power Facility.

G. The County has determined that, in light of the substantial financial investment and progress WPEA has made with respect to the Power Facility, it is prepared to enter into this Agreement.

AGREEMENT

For good and valuable consideration, the Parties agree as follows:

1. Use of the Water Rights. The County hereby commits and grants to WPEA the sole and exclusive right to develop, exercise and put to beneficial use the Water Rights for the construction, operation, maintenance, replacement, repair and reclamation of the Power Facility and including all uses ancillary thereto, for a total combined duty of up to and including 10,000 acre-ft annually of such Water Rights.

2. Term of Agreement. This Agreement shall become effective on the date written above and the term of this Agreement shall continue for the entire "Useful Life" of the Power Facility, subject only to the rights of termination contained this Agreement. "Useful Life" as used in this Agreement is defined as that period of time from the effective date of this Agreement until the Power Facility, as it may be modified, enhanced or replaced, has been permanently retired from service and the Water Rights are no longer needed for closure or reclamation of the Power Facility.

3. Ownership of the Water Rights. Title to the Water Rights shall at all times remain vested in the County. WPEA shall not be entitled to use the Water Rights for any purpose other than those expressly set forth herein.

4. Maintenance of the Water Rights. WPEA agrees to abide by all necessary rules and regulations promulgated by the State of Nevada related to the development, use and maintenance of the Water Rights for the Power Facility, and to perform at its own expense all filings and other activities required by such rules and regulations. The County agrees, upon execution of this Agreement, to provide written notification to the Nevada State Engineer that WPEA has the authority to perform such filings and activities and, to the extent necessary, the County shall timely ratify any such filings or actions made or taken by WPEA if required by the Nevada State Engineer. The Parties agree to provide each other with copies of all filings, notices or other communications either Party makes or receives in connection with the Water Rights.

5. Relinquishment of the Water Rights.

5.1 Water Rights Relinquished. Upon approval of this Agreement WPEA shall relinquish by written document WPEA's contract rights to 8,000 acre feet of water permits, numbered 72738; 72739; 72740; 72741; 72742; and, 72744, together with a pro rata rate of diversion.

5.2 Permits for Construction. Within 30 days of receipt of all unappealable, final permits for the construction of the Power Facility, WPEA shall provide notice to the County which Water Rights permits, or portions of thereof, are to be retained by WPEA to provide the 10,000 acre-ft of water required annually for the Power Facility. WPEA shall relinquish to the County the remaining 7,000 acre-ft of the Water Rights.

5.3 Other. WPEA may relinquish to the County all or any portion of the Water Rights at any time WPEA determines such Water Rights are no longer needed for the construction, operation, maintenance, replacement, repair and reclamation of the Power Facility. In the event, WPEA releases all or any portion of the Water Rights, WPEA shall provide such notice to the White Pine County and execute and deliver such documents as are reasonably necessary to reflect such relinquishment. WPEA shall thereafter be relieved of all further obligations under this Agreement with respect to the Water Rights so relinquished.

6. Responsibility, Payments and Costs.

6.1 Pre-Construction Payments. Upon execution of this Agreement, WPEA shall pay to County the sum of $2.00 per acre foot times 17,000 acre feet for a total of $34,000 per year or fraction thereof as consideration for this Water Supply Agreement. This payment shall cease upon commencement of construction.

6.2 Construction Payments. Upon commencement of construction WPEA shall pay to County a sum as and for consideration of the use of the leased water, $10.00 per acre foot times 10,000 acre feet annually for a total of $100,000 per year or fraction thereof during the construction phase; this payment shall cease upon commencement of commercial operations. Payments shall be made annually in advance and any necessary payment adjustments shall be settled at the end of the year.

6.3 Responsibility and Costs. WPEA shall be responsible for and shall bear all direct costs of permitting for and the construction, operation and maintenance of the wells, water pipelines, pumping stations, and other facilities required to place the Water Rights to beneficial use for the Power Facility, and of any pump tests or other tests or monitoring necessary to develop or maintain the Water Rights. Beyond the actions, and costs set forth in paragraphs 6.1 and 6.2 of this Agreement, WPEA shall not be required to pay the County a fee for use of the Water Rights, the consideration provided to the County through the Interim Agreement including, new jobs, an increased tax base and other economic benefits, being adequate consideration for this Agreement. In addition, upon termination of this Agreement at the end of the Useful Life of the Power Facility (i) any wells, pipelines, or other water-related facilities that have been constructed or installed in connection with the conveyance of water pursuant to the Water Rights to the Power Facility, not including any such facilities on the Power Facility site, and (ii) any available reports, data or other information developed by WPEA in connection with development of the Water Rights, shall, to the extent permitted, become the property of the County.

7. Cooperation. The County hereby agrees to cooperate as the owner of the Water Rights and to take any and all actions required of it for the proper development, permitting and utilization of the Water Rights for the Power Facility, including but not limited to any necessary changes in place of use or point of diversion required by WPEA for construction, operation, maintenance, modification, expansion, replacement, repair and reclamation of the Power Facility. Any such necessary filings shall be in the name of the County.

8. Exclusivity of Use. The County hereby commits and covenants that at all times during the term of this Agreement, except with respect to any portion of the Water Rights relinquished to the County by WPEA, the County will make no other commitments, verbal, implied, written or otherwise, of the Water Rights to any other third party during the term of this Agreement, nor will the County itself utilize or attempt to utilize such Water Rights except as may be necessary for construction, operation, maintenance, replacement, repair and reclamation of the Power Facility and with the agreement of WPEA. The County further commits and covenants that it will not, without the prior written consent of WPEA, (a) take any action which could cause the abandonment of the Water Rights or (b) apply for, seek or implement any action which would change the status of the Water Rights other than those actions required of the County to facilitate the construction, operation, maintenance, replacement, repair and reclamation of the Power Facility. The County may use, or may lease to third parties, any portion of the Water Rights so relinquished by WPEA to the County, but any such use or lease shall not in any manner affect the prior rights of WPEA. During the term of this Agreement, WPEA shall have the right to lodge protests with the Nevada State Engineer and oppose any applications to change which may conflict with the Water Rights utilized by WPEA.

9. Representations and Warranties. The County represents and warrants that, as of the date of execution of this Agreement and throughout its term, (a) the Water Rights are and will remain valid and in good standing under applicable law; (b) it holds title to the Water Rights free and clear of all liens, claims or other encumbrances, and has not contracted, optioned or otherwise obligated the Water Rights to any third party; (c) it has the authority to enter into this Agreement; and (e) the County has satisfied all legal preconditions to entering into this Agreement, including holding a public hearing and issuing written findings that meet the requirements of NRS § 533.550.

10. Assignment and Subordination. WPEA shall have the right to assign, subordinate or pledge this Agreement and its rights hereunder for the purpose of obtaining financing or otherwise funding development of the Power Facility without the consent of the County. WPEA shall also have the right to assign its rights under this Agreement to a successor in interest to the Power Facility or a portion thereof, provided, however, that any such assignment shall require the prior written consent of the County, which consent shall not be unreasonably withheld. The form of the consent and condition of the consent shall be governed solely by the requirement that the successor utilize the Water Rights for the purpose approved by the State of Nevada, and in accordance with this Agreement.

11. Termination.

11.1. Non-performance or Suspension. Subject to an event of Force Majeure, in the event that WPEA or its successor is unable to initiate construction of the Power Facility within five years of the effective date of this Agreement, or if WPEA or its successor begins construction or operation of the facility but then suspends such construction or operation for a period of more than five consecutive years, the County shall, upon 180 days written notice, have the right to terminate this Agreement unless WPEA initiates or resumes, as applicable, such construction or operation.

11.2. Perpetuities. To the extent that this Agreement could be construed to create, for purposes of the Nevada Rule Against Perpetuities (NRS § 111.103 et seq.), a non-vested property interest for any period of time, the Parties agree that such interest shall vest, if at all, within the time period allowed by such rule.

12. Rights and Remedies.

12.1 Default and Cure. If either Party believes that the other Party has defaulted in any material respect in the performance of any obligation under this Agreement, such Party shall notify the other Party in writing setting out specifically the nature of the default. The allegedly defaulting Party shall then be entitled to (a) cure such default within 30 days, (b) commence to cure the alleged default within 30 days and thereafter diligently complete such cure, or (c) challenge the legitimacy of the allegation. If the allegedly defaulting Party challenges the legitimacy of the allegation and it is finally determined in a court of competent jurisdiction that a default in fact occurred, the defaulting Party shall then have the right (x) to cure such default within 30 days or (y) to commence to cure the alleged default within 30 days and thereafter diligently completes such cure. The County agrees to notify any lenders of WPEA previously identified to the County by WPEA of any alleged default concurrently with any notification given to WPEA and to accept performance by such lenders of any obligation of WPEA under this Agreement.

12.2 Remedies. In the event a Party does not cure or challenge a default within the times permitted by Section 12.1, the other Party shall have all rights and remedies provided under Nevada law for a default under this Agreement. The Parties expressly acknowledge that in the event of a breach of this Agreement by the County, WPEA would be irreparably harmed and monetary damages would be inadequate. Accordingly, it is agreed that, in addition to any other remedy to which WPEA may be entitled at law or in equity, WPEA shall be entitled to an injunction (without the posting of any bond or other security and without proof of damages) to prevent breaches or threatened breaches of this Agreement and/or to compel specific performance of the Agreement. The Parties further acknowledge that such rights and remedies shall not be mutually exclusive, and the exercise of one or more of such rights and remedies shall not preclude the exercise of any other rights and remedies.

13. Notices. Any notice provided for in or concerning this Agreement shall be in writing and be deemed sufficiently given when sent by certified or registered United States mail or by

overnight delivery by a nationally recognized carrier to the respective address of the County and WPEA as set forth below:

If to the County: White Pine County Commission
Attn: Chairman
801 Clark Street, Suite 4
Ely, Nevada 89301
(775) 289-2341

White Pine County
Attn: District Attorney
801 Clark Street, Suite 3
Ely, Nevada 89301
(775) 289-8828

If to WPEA: White Pine Energy Associates, LLC
Attn: Project Manager
400 Chesterfield Center, Suite 110
St. Louis, MO 63017
(636) 532-2200 (v)
(636) 532-2250 (fax)

White Pine Energy Associates, LLC
Attn: General Counsel
Two Tower Center, 11th Floor
Newark, NJ 08816
(732) 249-6750 (v)
(732) 249-7290 (fax)

14. Recording. A copy of this Agreement shall be recorded in the official records of the White Pine County Recorder concurrently with the execution and delivery hereof and a copy shall also be filed with office of the Nevada State Engineer, Carson City, Nevada, with the applicable notice thereof being placed in Permits No. 72728 through 72749.

15. Effect on the Interim Agreement. To the extent this Agreement contains terms that are inconsistent with Section 10(a) of the Interim Agreement, this Agreement shall be an amendment of the Interim Agreement that supersedes and replaces such inconsistent terms.

16. Governing Law. This Agreement shall be governed by, construed, and enforced in accordance with the laws of the state of Nevada.

17. Entire Agreement. This Agreement shall constitute the entire agreement between the Parties and supersedes any prior understanding, representation, or agreement of the Parties regarding the subject matter hereof. Any modification of this Agreement or additional obligation

assumed by either Party in connection with this Agreement shall be binding only if evidenced in writing signed by each Party or an authorized representative of each Party.

18. No Waiver. No delay or failure by either Party to exercise any right under this Agreement, and no partial or single exercise of that right, shall constitute waiver of that or any other right, unless expressly provided herein. Either Party may, by notice delivered in the manner provided in this Agreement, but shall not be under obligation to, waive any of its rights or any conditions to its obligations hereunder, or any covenant or duty of any other Party. No waiver shall affect or alter the remainder of this Agreement, and each and every covenant, duty, and condition hereof shall continue in full force and effect with respect to any other then existing or subsequently occurring breach.

19. Necessary Acts and Further Assurances. The Parties hereby agree to do any act or thing and to execute any and all instruments required by this Agreement and which are necessary and proper to make effective the provisions of this Agreement. Such actions and additional instruments may include documents deemed reasonably necessary by WPEA to protect its interest under this Agreement and the recording and filing of additional or supplemental instruments in White Pine County or with the Nevada State Engineer from time to time.

20. Force Majeure. The failure to perform or to comply with any of the obligations under this Agreement, either expressed or implied, on the part of a Party shall not be a ground for termination of this Agreement, and such Party shall not be liable for failure to perform its obligations during any period in which performance is prevented, in whole or part, by events of "Force Majeure".

20.1 Definition of "Force Majeure." The term "Force Majeure" shall include events or causes beyond the reasonable control of a Party including labor disputes; acts of God; actions of the elements, including inclement weather, floods, slides, cave-ins, sinkholes, earthquakes, and drought; laws, rules, regulations, orders, directives, and requests of governmental bodies or agencies; delay, failure, or inability of suppliers or transporters of materials, parts, supplies, services, or equipment; contractor or subcontractor shortage of labor, transportation, materials, machinery, equipment, supplies, utilities, or services; accidents; breakdown of equipment, machinery, or facilities; prolonged litigation, judgments or orders of any court; inability to obtain on reasonably acceptable terms or in reasonably acceptable time any public or private licenses, permits, or other authorizations; curtailment or suspension of activities to remedy or avoid an actual or alleged, present, or future violation of federal, state, or local environmental standard; acts of war or conditions arising out of or attributable to war, whether declared or undeclared; riot; civil strife; fire; explosion; or any other cause whatsoever beyond the control of such Party, whether similar or dissimilar to the foregoing, except for the inability to meet financial commitments.

20.2 Use of Force Majeure. If a Party is delayed in or prevented from performing any obligation by any such cause, the time of such delay or interruption shall not be counted against the term hereof, and this Agreement shall be extended while and so long as such performance is delayed or prevented. If a Party desires to invoke the provisions of this section 18, it shall give notice of the event or condition causing Force Majeure and

thereafter advise the other Party with respect to its efforts to resolve the situation causing Force Majeure and of termination of such event or condition.

21. Authorization. Each individual executing this Agreement does thereby represent and warrant that he or she has been duly authorized to sign this Agreement in the capacity on behalf of the entities it represents.

22. Execution of Agreement. This Agreement may be executed in counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the day and year last written below.

White Pine County

attest:
Donna M Bath
WPCO Clerk

By: Gary Eddy
Its: Chairman
Date: February 13, 2008

White Pine Energy Associates, LLC

By: Paul Thomsen
Its: VP
Date: 2/19/08

EXHIBIT A
To
Water Supply Agreement

[attach copies of the permits]

Appendix C

Best Management Practices

APPENDIX C

Best Management Practices

This appendix describes a number of Best Management Practices (BMPs) intended to reduce the potential for short- and long-term impacts. These BMPs will be implemented during construction and operation of the White Pine Energy Station. These BMPs will be incorporated into all construction specifications and contract documents, as appropriate, and all contractors will be required to follow them. These BMPs are an integral part of the Proposed Action and Alternative 1.

Air Pollution Prevention

1. Contractors will be required to comply with all applicable federal, state, and local laws and regulations concerning prevention and control of air pollution during facility construction and operation.

2. Contractors will obtain applicable air quality permits before starting construction or operating equipment that will result in regulated atmospheric emissions.

3. Contractors will be required to implement measures to minimize dust emissions from construction operations. To accomplish this, the following measures will be implemented:

   - For the duration of construction activities, actively disturbed areas will be stabilized through the use of wet suppression as required to meet ambient air quality standards. Adequate supplies of water for dust suppression will be available such that chemical dust suppressants will not be necessary for dust control. Disturbed areas, including storage piles not being actively used for a period of 1 week or longer, will be stabilized as appropriate to minimize dust emissions. Active stabilization may not be required if soil moisture or natural crusting is sufficient to limit ambient impacts.

   - Bulk material stored onsite that is a possible fugitive dust source will be actively wetted, as needed, to minimize ambient impacts. It is anticipated that the majority of the material will be used onsite upon arrival. Should bulk materials require onsite storage for an extended period of time, the application of active wet suppression or the installation of a porous wind fence will be used as necessary to minimize fugitive dust generation.

   - Onsite fugitive dust emissions will be limited by reducing vehicle speeds and a combination of active and passive dust suppression measures. BMPs will include the following:

     - Onsite access roads, parking lots, and lay-down areas will be maintained with a gravel cover or paved to the extent practical.

     - Unpaved road segments will be watered as necessary.

- Traffic on off-site dirt roads will be restricted to the posted speed limit to minimize emissions from unpaved road segments.
- Combustion emissions from mobile sources will be minimized by proper maintenance and tune-up of equipment.

4. The project will comply with all applicable federal, state, and local laws and regulations concerning prevention and control of air pollution during facility operation. The project will receive a Prevention of Significant Deterioration (PSD) Permit prior to construction that will establish air emission rate limitations and specify air emission control technologies for facility operation.
5. Air emission sources regulated under the PSD Permit are expected to include the following:

   - Combustion sources
     - Pulverized coal boilers
     - Auxiliary boiler
     - Back-up electric generator(s)
     - Emergency diesel firewater pump
   - Non-combustion particulate matter sources
     - Cooling towers
     - Coal unloading, handling, and storage areas
     - Lime unloading, handling, and storage systems
     - Unpaved and paved roadway travel
     - Solid waste disposal facility operations
   - Liquid fuel storage sources
     - No. 2 fuel oil tank
     - Diesel fuel tanks
     - Gasoline tanks

   Air emissions from the sources listed above will be minimized through the design of these sources, use of air pollution control equipment, good combustion practices, and pollution prevention methods, all as specified in the PSD Permit.

Landscape Preservation and Impact Avoidance

1. To the maximum extent practical, all trees, native shrubs, and other vegetation will be preserved and protected during construction operations except where clearing operations are required for structures and equipment, approved construction and permanent roads, construction yards and staging areas, and excavation operations.
2. All areas around water pipelines, wells, and transmission line structures will be backfilled, compacted, and returned as close as possible to the original condition and grade.

3. Ephemeral drainages, steep slopes, or sensitive environmental areas will not be used for equipment or materials storage or stockpiling; construction staging or maintenance; field offices; hazardous material or fuel storage, handling, or transfer; or temporary access roads.
4. Excavated or graded materials will not be stockpiled or deposited on or within 100 feet of any steep slopes (defined by industry standards) or seasonally active ephemeral drainages.
5. The width of all new temporary access roads will be kept to the absolute minimum needed for operation, avoiding sensitive areas and trees where possible, and limiting disturbance to vegetation.
6. When and where applicable, landscaping standards, including clearing of native vegetation, will be followed as prescribed by local land use and management agencies when work is within their jurisdictions.

Erosion and Sediment Control

1. Planting of native grasses, forbs, trees, or shrubs beneficial to wildlife, or placing of riprap and other materials as appropriate, will be used to prevent and minimize the potential for erosion and siltation during construction of project features and during the period needed to reestablish permanent vegetative cover on disturbed sites. Sediment fences will be used where appropriate to limit wind and water erosion, and water trucks will be used in disturbed areas during construction to limit wind erosion.
2. Final erosion control and site restoration measures will be initiated as soon as practical after a particular area is no longer needed for construction, stockpiling, or access. Clearing schedules will be arranged to minimize exposure of soils.
3. Cuts and fills for access roads and utility corridors will be sloped to prevent landslides and to facilitate revegetation.
4. Signs will be placed along the access road to discourage off-road vehicle use of adjacent areas.
5. Borrow areas will be contoured and shaped to carry the natural contour of adjacent undisturbed terrain into the borrow area.
6. Soil or rock stockpiles, excavated materials, or excess soil materials will not be placed near sensitive habitats, including perennial, intermittent, and ephemeral drainages, where they may erode into these habitats or be washed away by high water or storm runoff. Plastic will be placed over stockpiles to prevent wind erosion if the stockpiles are intended to be long-term. Waste piles will be revegetated using suitable native species after they are shaped to provide a natural appearance.
7. Treading on areas not immediately involved in project construction activities will be avoided to reduce potential wind erosion and fugitive dust generated during construction.

Pipeline and Utility Corridor Construction

1. The upper 12 to 18 inches of soil will be removed from the trench area and stockpiled for later use.
2. Surface elevations will be returned to pre-project conditions, taking into account expected settling.
3. Construction activities in ephemeral washes crossed by linear features would not occur during the wet or rainy season in order to minimize or avoid the potential for short-term impacts to hydrology, vegetation, soils, and aquatic habitat for amphibians and other wildlife.
4. Where the pipeline crosses fences, a wire gate will be installed to standard BLM specifications. The gates will be built prior to the corridor construction and will be kept closed except during active construction at the fence site.
5. If construction activities cause damage to existing range improvements (such as pipelines, fences, troughs, etc.), they will be fixed using material that meets or exceeds the quality of the existing improvement. If damage occurs, the BLM and livestock operator will be notified immediately. If damage occurs during active livestock grazing, repairs will be made within 24 hours.
6. The base of guy-wires on power poles will be fenced, and the first 10 feet of guy-wires will be marked with safety reflectors, high-visibility tape or plastic, or a similar material to make them highly visible to the public and to avian and mobile terrestrial wildlife species.

Biological Resources

1. Biological resources in the project area will be evaluated and the presence of any federally-listed endangered, threatened, or candidate species noted. The U.S. Fish and Wildlife Service (FWS) will be consulted per requirements of Section 7 of the Endangered Species Act (ESA). Measures will be incorporated into the Plan of Development to avoid impacts to endangered, threatened, and candidate species and their habitats. Where such impacts cannot be avoided, the project final design, construction, and operation will include appropriate measures to minimize and mitigate impacts.
2. Bird nests encountered during land disturbing construction activities will be avoided while the birds are fledging. To the extent practical, land disturbing construction activities will be scheduled outside of the breeding season (March 15 through July 30). If construction is required during the breeding season, the area impacted will be surveyed for nests prior to construction.
3. WPEA will adhere to an integrated pest management plan prepared for the project.
4. The evaporation pond on the power plant site will be fenced to exclude access by terrestrial wildlife species. In addition, the pond liner will be textured and there will be wildlife escape ramps at regular intervals on the liner. The evaporation pond will be monitored for water quality, use by wildlife, and possible adverse effects on wildlife

resulting from exposure to potentially highly saline pond water. If necessary, measures that are designed to prevent or discourage wildlife from entering the pond will be initiated prior to when critical salinity levels are reached that could adversely impact wildlife. Examples of such measures include electronic sound devices that mimic predatory bird calls, visual scare tactics, propane noise cannons, and, in extreme cases, netting. The monitoring program and protective measures that will be implemented, if needed, will be described in the Plan of Development. The process will be completed in consultation with a BLM biologist.

5. Also refer to BMPs under Pipeline and Utility Corridor Construction and Reclamation for the protection of Biological Resources.
6. An observer will be present to visually search for and make sure no bald eagles are present in the power plant area prior to steam blowouts.
7. Biological crusts will not be disturbed if encountered.
8. Surveys for special status and BLM sensitive plant species will be conducted prior to construction and, if necessary, appropriate mitigation agreed to by WPEA and the BLM will be followed.

Cultural Resources

See the Cultural Resources Programmatic Agreement contained in Appendix O.

Paleontological Resources

1. If paleontological resources are discovered during construction, the BLM will be notified immediately and measures taken to protect the resource. A 50-meter buffer will be left around any discovery and work will not resume until authorization is given by an authorized officer. The significance of the resource will be evaluated and whether or not avoidance was possible. Stabilization and measures to mitigate construction damage might also be required even if avoidance was possible. Should avoidance prove infeasible, further procedures to protect the resource will be determined by the BLM.
2. The BLM's Paleontological Resource Management Program (BLM Manual 8720) includes the following objectives:
    - Locate, evaluate, manage, and protect, where appropriate, paleontological resources on public lands.
    - Facilitate the appropriate scientific, educational, and recreational uses of paleontological resources, such as research and interpretation.
    - Ensure that proposed land uses, initiated or authorized by the BLM, do not inadvertently damage or destroy important paleontological resources on public lands.
    - Foster public awareness and appreciation of our nation's rich paleontological heritage.

Noxious and Invasive Weed Management

1. Prior to the acquisition of non-federal lands, a noxious weed assessment will be conducted so that the BLM Authorized Officer can factor the cost of weed control into the acquisition decision.

2. A noxious weed survey will be completed prior to any earth disturbing activity including cross-country travel. Noxious or invasive weeds that may be located on the site will be managed according to methods to be approved by the BLM Authorized Officer. Should chemical methods be approved, the lessee must submit a Pesticide Use Proposal to the Authorized Officer 60 days prior to the planned application date. A Pesticide Application Report must be submitted to the Authorized Officer by the end of each fiscal year following chemical application.

3. To eliminate the introduction of noxious weed seeds, roots, or rhizomes, all straw, hay, straw/hay, or other organic products used for reclamation or stabilization activities will be certified free of plant species listed on the Nevada noxious weed list or specifically identified by the BLM Ely Field Office.

4. To eliminate the introduction of noxious weed seeds, roots, or rhizomes, all source sites such as borrow pits, fill sources, or gravel pits used to supply inorganic materials used for construction, maintenance, or reclamation will be inspected and found to be free of plant species listed on the Nevada noxious weed list or specifically identified by the BLM Ely Field Office. Inspections will be conducted by a BLM-approved weed scientist or qualified biologist.

5. To eliminate the transport of vehicle-borne weed seeds, roots, or rhizomes, all vehicles and heavy equipment used for the completion, maintenance, inspection, or monitoring of ground disturbing activities will be free of soil and debris capable of transporting weed propagules. All such vehicles and equipment will be cleaned with power or high pressure equipment prior to entering or leaving the work site or project area. Cleaning efforts will concentrate on tracks, feet or tires, and on the undercarriage. Special emphasis will be applied to axles, frames, cross members, motor mounts, on and underneath steps, running boards, and front bumper/brush guard assemblies. Vehicle cabs will be swept out and refuse will be disposed of in waste receptacles. Cleaning sites will be recorded using global positioning systems or other mutually acceptable equipment and provided to the Field Office Weed Coordinator or designated contact person.

6. Prior to entry of vehicles and equipment to a project area, areas of concern will be identified and flagged in the field by a weed scientist or qualified biologist. The flagging will alert personnel or participants to avoid areas of concern. These sites will be recorded using global positioning systems or other Ely Field Office approved equipment and provided to the Field Office Weed Coordinator or designated contact person.

7. Prior to entering public lands, the contractor, operator, or permit holder will provide information and training regarding noxious weed management and identification to all personnel who will be affiliated with the implementation and maintenance phases of the project. The importance of preventing the spread of weeds to uninfested areas and the importance of controlling existing populations of weeds will be explained.

8. To eliminate the transport of soil-borne noxious weed seeds, roots, or rhizomes, infested soils or materials will not be moved and redistributed on weed-free or relatively weed-free areas. In areas where infestations are identified or noted and infested soils, rock, or overburden must be moved, these materials will be salvaged and stockpiled adjacent to the area from which they were stripped. Appropriate measures will be taken to minimize wind and water erosion of these stockpiles. During reclamation, the materials will be returned to the area from which they were stripped.

9. Prior to project approval, a site-specific weed survey will occur and a weed risk assessment will be completed. Monitoring will be conducted for a period no shorter than the life of the permit or until bond release and monitoring reports will be provided to the BLM. If the spread of noxious weeds is noted, appropriated weed control procedures will be determined in consultation with BLM personnel and will be in compliance with the appropriate BLM Handbook sections and applicable laws and regulations. All weed control efforts on BLM-administered lands will be in compliance with BLM Handbook H-9011, H-9011-1 Chemical Pest Control, H-9014 Use of Biological Control Agents of Pests on Public Lands, and H-9015 Integrated Pest Management. A pesticide Application Report must be submitted to the Authorized Officer by the end of the fiscal year follow chemical application.

10. For mineral activity, bonds for weed control will be retained until the site is returned to desired vegetative conditions.

11. Removal and disturbance of vegetation will be kept to a minimum through construction site management (for example, using previously disturbed areas and existing easements, limiting equipment/materials storage and staging area sites, etc.)

12. Mixing of herbicides and rinsing of herbicide containers and spray equipment will be conducted only in areas that are safe distance from environmentally sensitive areas and points of entry to bodies of water (storm drains, irrigation ditches, streams, lakes, or wells).

13. Methods used to accomplish weed and insect control objectives will consider seasonal distribution of large wildlife species.

Reclamation

1. Reclamation will normally be accomplished with native species only. These will be representative of the indigenous species present in the adjacent habitat. Rationale for potential planting with selected non-natives will be documented. Possible exceptions could include use of non-natives for a temporary cover crop to out-compete weeds.

2. Seeding will occur during October 15 through March 15 to ensure a greater chance of success.

3. Reclamation release criteria are as follows:

    - Achieve 100 percent of the perennial plant cover of selected comparison areas, normally like adjacent habitat. If the adjacent habitat is severely disturbed, a range site description may be used as a cover standard. Cover is normally crown cover as

estimated by the point intercept method. Selected cover can be determined using a method as described in *Sampling Vegetation Attributes, Interagency Technical Reference* (1996, BLM/RS/ST-96/002+1730). The reclamation plan for the project area will identify the site-specific release criteria and associated statistical methods in the reclamation plan or permit.

- No noxious weeds will be allowed on the sites for reclamation release. Control of noxious weeds will follow an integrated pest management plan approved by the authorizing officer. A list of Nevada noxious weeds will be provided by the authorized officer.

4. Up to the first 12 to 18 inches of growth medium will be salvaged and stockpiled prior to disturbance for all areas to be reclaimed after construction. All disturbance areas to be reclaimed will be recontoured to blend as nearly as possible with the natural topography prior to revegetation. All compacted portions of the disturbance will be ripped to a depth of 12 inches unless solid rock is encountered. Adequate, fine-grain seedbed must be established to provide good seed to soil contact. Large blocks and clumps of soil with deep pockets should be avoided. This normally requires some type of tillage procedure after ripping.
5. All portions of access roads not needed for other uses as determined by the authorized officer will be reclaimed.
6. Mulching of the seedbed following seeding may be required under certain conditions, such as severe erosion.
7. The success of the vegetative growth on a reclaimed site may be evaluated for release no sooner than during the third growing season after earthwork and planting have been completed. Where it has been determined that revegetation success criteria have not been met, the agencies and the operator will meet to decide on the best course of actions necessary to meet the reclamation goal.
8. Where applicable, the following agencies will be consulted to determine the recommended plant species composition, seeding rates, and planting dates:
   - U.S. Fish and Wildlife Service (FWS)
   - U.S. Natural Resources Conservation Service (NRCS)
   - U.S. Bureau of Land Management (BLM)
9. Grasses, forbs, shrubs, and trees appropriate for site conditions and surrounding vegetation will be included on the plant list. Species chosen for a site will be matched for site drainage, climate, shading, resistance to erosion, soil type, slope, aspect, and vegetation management goals. Upland revegetation shall match the plant list to the site's soil type, topographic position, elevation, and surrounding natural communities.
10. Construction areas, including storage yards, will be free of waste material and trash accumulations at all times, unless stored in appropriate containers.
11. All unused materials and trash will be removed from construction and storage sites during the final phase of work. All removed material will be placed in approved sanitary landfills or storage sites and work areas will be left to conform to the natural landscape.

12. Upon completion of construction, any land disturbed will be graded to provide proper drainage and blend with the natural contour of the land. Following grading, it will be revegetated using plants native to the area, suitable for the site conditions, and beneficial to wildlife.
13. Following completion of construction, all yards, offices, and construction buildings, including concrete footings and slabs, will be removed from the site.
14. All temporary construction roads will be obliterated and restored to the original contour, and made to discourage vehicular traffic when no longer needed by contractors. Culverts will be removed as appropriate, road escarpments will be contoured and vegetated, and all road surfaces will be scarified to establish conditions appropriate for reseeding, drainage, and erosion prevention.

Visual Resources

1. All outside surfaces of structures, stacks, buildings, and tanks will be constructed of materials that will restrict glare, and will be finished with flat tones intended to blend with the surrounding predominantly rural environment. WPEA will consult with White Pine County and BLM regarding the final selection of colors for the features of the property.
2. All fencing will be constructed of non-reflective materials, and will be treated or painted to blend with the surrounding environment.
3. Signs at the plant site will be constructed of materials that are non-glare, and will be painted using unobtrusive colors. This requirement shall not apply to safety signs (for example, brightly colored signs indicating the presence of a hazard.)
4. Outdoor lighting will be limited to areas required for operations, maintenance, safety and security, and will be shielded and directed downward to the extent possible. Highly directional, high-pressure sodium vapor fixtures (or other fixtures that meet the criteria specified) will be used where practical. Switches will be used as appropriate on outdoor lighting to allow use of lighting only when needed. Lighting techniques will include using directional lights that do not allow lights to shine into the sky, screening lights, using timers and motion detectors so that lights are only on when necessary, and designing a lighting system than minimizes lighting to only meet functional requirements.
5. The transmission structures will be finished with flat, neutral gray tones that will relate to the colors of the structures in the existing transmission corridors and that will blend with the surrounding environment.
6. Non-specular conductors and non-reflective and non-refractive insulators will be used to reduce conductor and insulator visibility.
7. Also refer to BMP No. 5 under Pipeline and Utility Corridor Construction for Visual Resources guidelines.

Water Pollution Prevention and Monitoring

1. Water needs during facility operation (up to 5,000 acre-feet annually) will be supplied through water rights that have been permitted under application Numbers 45834 through 45855 and are held by White Pine County. Water needs during facility construction will be supplied by one or more of the project's permitted wells or transported by truck from other local water sources.
2. A ground water monitoring program will be developed by WPEA in cooperation with the Nevada State Engineer. Results of monitoring will be provided to the BLM and the Nevada State Engineer annually to evaluate the effects of the withdrawal of ground water resources in accordance with Condition 3 of the water rights permits.
3. Pumped ground water will be monitored periodically (as stipulated in the final Construction, Operation, and Maintenance Plan) to ensure its quality is suitable for power plant operation, including its use as potable water supplies for plant employees, boiler feedwater makeup, cooling water makeup, pollution control, and other beneficial uses to support the operation of the facility.
4. All federal and state laws related to control and abatement of water pollution will be complied with. All waste material and sewage from construction activities or project-related features will be disposed of according to federal and state pollution control regulations.
5. All disturbed drainages will be reclaimed as soon as practical, to a standard for aesthetic value comparable to what existed prior to disturbance. Where appropriate, native species capable of bank stabilization will be used to revegetate all disturbed banks.
6. Diversion structures will be used to re-direct flows from any drainages potentially impacted by facility features and will be designed to minimize potential destabilization and erosion of adjacent and downgradient drainages.
7. Stormwater management plans will be implemented for project construction and facility operation to minimize and control erosion from stormwater runoff. During project construction, stormwater will be managed in compliance with applicable state and federal regulations, including compliance with requirements of the National Pollutant Discharge Elimination System (NPDES) stormwater general permits, which will be obtained for the project. Stormwater management elements will include:
    - Application of best management practices for erosion, sedimentation, and stabilization control during construction activities, and management of oils and other substances during operation to minimize contact with stormwater
    - Structural controls during operation that could include stabilized stormwater conveyance systems (swales), oil-water separators for runoff that comes in contact with affected plant site surfaces, and sedimentation detention basins
    - Monitoring and maintenance to ensure long-term effectiveness of the management system.

8. One or more stormwater retention basins will be constructed with sufficient dimensions to accommodate runoff from the impervious surfaces at the plant site generated by the local maximum daily rainfall event with a return frequency of 100 years or less. All runoff from the impervious surfaces will be directed to the retention basin(s) prior to being released to the natural drainage system at flow rates equivalent to pre-development conditions. Stormwater runoff likely to contain contaminants will flow first to onsite treatment facilities (such as an oil-water separator), as appropriate, prior to being directed to the stormwater retention basin(s).

9. Construction specifications will require construction methods that prevent pollutants from accidentally entering or spilling into flowing or dry watercourses, and ground water sources. Potential pollutants and wastes include refuse, garbage, cement, concrete, sewage effluent, industrial waste, oil and other petroleum products, aggregate processing tailings, mineral salts, drilling mud, and thermal pollution.

10. A detailed containment plan will be developed and included in the Plan of Development for the disposal of drilling mud and test-drilling water associated with and removed during the drilling of ground water wells.

11. Any construction wastewater discharged into surface waters will be essentially free of settling material. Wastewater from aggregate processing, concrete batching, or other construction operation will not enter drainages without water quality treatment. Turbidity control methods may include settling ponds; gravel-filter entrapment dikes; recirculation systems for washing aggregates; or other approved methods.

12. Appendix I contains a ground water monitoring program.

Noise Prevention

1. The facility will be designed to operate in compliance with all applicable federal, state, and local laws and regulations related to noise.

2. Contractors will be required to comply with all applicable federal, state, and local laws and regulations concerning prevention and control of noise during project construction and operation.

Hazardous Material Storage, Handling, and Disposal and Safety Measures

1. Contractors will be required to comply with Nevada State Regulations established under the authority of the Federal Resources Conservation and Recovery Act of 1976.

2. "Hazardous material" means any substance, pollutant, or contaminant that is listed as hazardous under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended, 42 USC 9601 et seq., and its regulations (CERCLA). The definition of hazardous substances under CERCLA includes any "hazardous waste" as defined in the Resource Conservation and Recovery Act of 1976 (RCRA), as amended 42 USC 6901 et seq., and its regulations. The term hazardous materials also includes any

nuclear byproduct material as defined by the Atomic Energy Act of 1954 as amended, 42 USC 2011 et seq.

3. As necessary, process wastewater solid precipitant will be transported for disposal at a licensed landfill. Solid precipitant stored onsite will be covered until transported for disposal.
4. Aboveground chemical tanks will be located within a containment structure that is paved and bermed, and that is sufficient to contain a release from the largest tank within the area, plus sufficient freeboard to prevent overflow. Tanks will be registered, constructed, and managed using accepted engineering best practices, which may include high-level alarms or indicators to prevent overflow and locking valves. Tanks will be subject to a regular inspection regime (as stipulated in the final Construction, Operation, and Maintenance Plan).
5. The potential for adverse impacts from oil and fuel spills will be reduced through careful handling and designation of specific equipment repair and fuel storage areas.
6. Outdoor oil storage areas will be bermed with a capacity sufficient to contain the oil inventory contained in the single largest tank/equipment plus sufficient freeboard to prevent overflow. These areas will be equipped with a normally locked valve. Regular inspections will determine if there had been a leak requiring special attention. Otherwise, the valve will be opened to drain any rainwater to a plant oil/water separator. Any oil collected in the separator will be pumped out and removed by a licensed oil disposal contractor.
7. Outdoor chemical and hazardous waste storage areas will be within diked containment areas. Chemicals and wastes will be stored in accordance with the fire safety, hazardous materials management, and hazardous waste management standards of practice, which include segregation of incompatibles, protection of water-reactive materials from precipitation or moisture, adequate aisle space, etc.
8. Waste materials known or found to be hazardous will be disposed of in approved treatment or disposal facilities in accordance with federal, state, and local regulations, standards, codes, and laws.
9. Solid waste will be stored in onsite roll-off bins. Recyclable materials will be separated from the solid waste stream. Solid waste will be collected periodically and transported to a local licensed landfill.
10. Generation of wastes during construction will be minimized through detailed estimating of materials needed and through efficient construction practices. Any wastes generated during construction will be recycled as much as feasible. Concrete waste will be used as fill onsite, or, if not suitable for reuse, will be removed to a local licensed landfill. Any nonrecyclable wastes will be collected and transported to a local licensed landfill.
11. Fuels, lubricant chemicals, and welding gases used during construction will be in controlled storage until used. Any empty containers or waste material will be segregated in storage and properly recycled or disposed of by licensed handlers.

12. Concrete trucks will not be washed at construction sites along utility corridors. Concrete trucks may be washed at designated locations on the power plant site. All spilled concrete will be removed from construction areas and disposed of properly.

13. Portable toilets will be provided for onsite sewage handling during construction. Sewage from the portable toilets will be removed regularly and disposed of in accordance with applicable federal and state pollution control regulations. During facility operation, sewage from plant employees will be collected and treated using an on-site septic system.

14. A Spill Prevention Control and Countermeasures Plan (SPCCP) will be put in place for project features and include the following:

    - Program components and assignments
    - Professional engineer certification
    - Site information
    - Site drainage and storm water management
    - Emergency procedures/spill response
    - Emergency reporting contacts
    - Tank schematics
    - Material safety data sheets
    - Management approval
    - Plans reviews and amendments
    - Personnel training
    - Reporting procedures/emergency reporting contacts
    - Site inspections
    - Notice to tank truck drivers
    - Spill, fire, and safety equipment

15. Operators of the White Pine Energy Station will provide first response fire and emergency medical equipment and services for the project. The operators will also coordinate with local police, fire, and ambulance districts to provide additional personnel and services to the project.

16. To minimize the exposure of personnel and equipment to potential flood hazards, construction activities in or immediately adjacent to drainages will be scheduled to occur when the probability for flash flooding is minimal.

Socioeconomics

1. WPEA will provide funding for the additional resources, if needed, that will be identified by White Pine County so that there are no interim service deficiencies.

2. Security-related BMPs included as part of the plant site development will include an onsite security office to provide space and facilities for security personnel, a guardhouse for security personnel at the entrance to the power plant site, security fencing around the power plant site, and security vehicles to patrol the site.

3. Speed limit and caution signs will be placed near construction sites and access routes.

4. Traffic control personnel will be employed at road crossings and construction access ingress and egress sites to minimize the potential increase in demand for sheriff patrols and reduce the need for issuing speeding tickets.
5. To support the effectiveness of first responders, the plant site will have extra water storage for firefighting effort that might be necessary prior to the arrival of firefighting personnel from McGill or Ely. Backup diesel generators and pumps, water trucks, and other equipment will also be maintained and kept on the plant site.
6. The plant site will incorporate a wide range of safety features to minimize the risk of injury that could require medical attention including:
   - Public access to the power plant site will be restricted through the use of fencing and security gates
   - The power plant will be equipped with fire suppression systems
   - Industry-recognized BMPs will be implemented to minimize fire safety risks

Appendix D

Evaluation of Alternative Control Strategies

Report

Evaluation of Alternative Control Strategies

Prepared for

U.S. Bureau of Land Management

Ely Field Office, Nevada

Contents

1.0 Introduction

1.1 Criteria Pollutants

The Clean Air Act requires EPA to set National Ambient Air Quality Standards for pollutants considered harmful to public health and the environment. These pollutants, commonly referred to as Criteria Pollutants are as follows:

- Nitrogen dioxide (NO_2)
- Carbon monoxides (CO)
- Sulfur oxides (SO_2)
- Particulate matter less than 10 microns (PM_{10})
- Particulate matter less than 2.5 microns ($PM_{2.5}$)
- Ozone
- Lead

Emission limits and controls of these pollutants are regulated under 40 CFR 52.21 (Prevention of Significant Deterioration) and 40 CFR 60 (New Source Performance Standards).

1.2 Hazardous Air Pollutants

The U.S. Congress amended the Clean Air Act in 1990 (Section 112) to address a large number of air pollutants that are known to cause or may reasonably be anticipated to cause adverse effects to human health or adverse environmental effects. These 188 specific pollutants and chemical groups were initially identified as Hazardous Air Pollutants (HAPs) or sometimes referred to as Air Toxics.

For a complete listing of HAPs refer to EPA's Technology Transfer Network, Air Toxics Web Site (http://www.epa.gov/ttn/atw/188polls.html). Common HAPs emitted from a coal fired power plant include organic compounds, acid gases, and trace metals (including mercury).

1.2.1 Organic Compounds

Organic compounds (some of which are classified as HAPs) include volatile, semivolatile, and condensable organic compounds either present in the coal or formed as a product of incomplete combustion (PIC). These compounds may include the following:

- Alkanes
- Benzene
- Polychlorinated
- Dibenzo-p-dioxins
- Alkenes
- Toluene
- Polychlorinated
- Dibenzofurans
- Aldehydes
- Xylene
- Polycyclic organic matter
- Alcohols
- Ethyl benzene
- Polynuclear aromatic hydrocarbons

These pollutants are usually referred to as volatile organic compounds (VOCs) which are precursors of ozone. Emissions of VOCs are largely dependent on combustion controls. Combustion controls include the use of operational and design elements that optimize the amount and distribution of excess air in the combustion zone to ensure complete and efficient combustion. However, these same control factors can increase NO_x emissions. Conversely, lower NO_x emission rates achieved through flame temperature control can increase VOC and CO emissions.

1.2.2 Acid Gases

When coal is combusted, a fraction of the chlorine and fluorine in the coal is converted to hydrochloric acid (HCL) and hydrogen fluoride (HF). These are known as acid gases and are effectively removed by the FGD system. It should be noted that depending on the design of the FGD system (wet, spray dry, or dry scrubbers), sulphuric acid (H_2SO_4) emission may be increased. While H_2SO_4 is not a HAP, it is a Prevention of Significant Deterioration (PSD) regulated pollutant discussed in the following Section 1.3.

1.2.3 Trace Metals

Once combusted, the trace metals in the coal may be emitted in the exhaust stream. Various classification schemes have been developed to describe this partitioning behavior (source EPA's AP 42, Fifth Edition, Volume I, Chapter 1.1). These classification schemes generally distinguish among the following:

- Class 1—Elements that are approximately equally concentrated in the fly ash and bottom ash, or show little or no small particle enrichment. Examples include manganese, beryllium, cobalt, and chromium.
- Class 2—Elements that are enriched in fly ash relative to bottom ash, or show increasing enrichment with decreasing particle size. Examples include arsenic, cadmium, lead, and antimony.
- Class 3—Elements which are emitted in the gas phase (primarily mercury and, in some cases, selenium).

Control of Class 1 and Class 2 metals is directly related to control of total particulate matter emissions. Because of the volatility of Class 3 metals, particulate controls have only a limited impact on emissions of these metals.

1.3 Prevention of Significant Deterioration Pollutants

Prevention of Significant Deterioration (PSD) Pollutants and their significance thresholds are defined in 40 CFR 52.21(J) and are shown in Table 1. These pollutants are made up of criteria, hazardous, and other air pollutants.

TABLE 1
PSD Pollutants and Significant Thresholds

Pollutant	Significance Emission Rate (tons per year)
NO_x	40
CO	100
SO_2	40
PM (total suspended particulate)	25
PM_{10}	15
Ozone (of VOC or NO_X)	40
Lead	0.6
Fluorides	3
H_2SO_4	10
H_2S	10
Total reduced sulfur (including H_2S):	10
Reduced sulfur compounds (including H_2S)	10

Facilities that that are being permitted under the PSD rules and have emissions that exceed the threshold in Table 1 are required to conduct a Best Available Control Technology (BACT) analysis as discussed in Section 2.0.

1.4 Greenhouse Gases

Greenhouse gases are components in the atmosphere that contribute to the greenhouse effect (see Appendix M of this FEIS for additional information on greenhouse gases, the greenhouse effect, and climate change). Some greenhouse gases are emitted to the atmosphere through natural processes, while others result from human activities such as burning of fossil fuels. The primary greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone.

No Nevada state regulations or federal regulations limit greenhouse gas emissions or require the addition of control technology on a stationary source such as a power plant.

1.5 Summary of Pollution Control Strategy

A summary of the White Pine Energy Stations pollution control strategy for the PC-fired boilers is shown in Table 2.

TABLE 2
Summary of Pollution Control Strategy

Pollutant	Control Technology
NO_x	Low NO_x burners Overfire air Selective catalytic reduction
CO	Combustion controls
SO_2	Low-sulfur coal, dry scrubber
VOC	Combustion Controls
Fluorides	Dry scrubber and Fabric filter baghouse
H_2SO_4	Low-sulfur coal, dry scrubber, and Fabric filter baghouse
PM_{10} and non-volatile metals	Fabric filter baghouse
Volatile Metals (Hg)	Halogenated activated carbon and Fabric filer baghouse
CO_2	Efficient generation technology Future add-on technologies to be evaluated

It should be noted that in the evaluating pollution control strategy, there may be tradeoffs with environment impacts that need to be taken into account. The lowest air emission rate for one pollutant does not necessarily result in the lowest overall environmental impact. It is possible to produce more of one pollutant while trying to control another. Examples include the potential increase of ammonia emissions when controlling for NO_x or the increase H_2SO_4 when controlling for SO_2. Other environmental tradeoffs could include electrical efficiency and conservation, conservation of water recourses, and the minimization of wastes that are generated in the pollution control process.

2.0 PSD/Best Available Control Technology

As applicable, the control technologies for the pulverized coal (PC)-fired boilers were selected through the BACT analysis that was conducted as a part of White Pine Energy Associates' (WPEA's) PSD air permit application, which was reviewed and approved by the Nevada Division of Environmental Protection-Bureau of Air Pollution Control (NDEP-BAPC).

In brief, the PSD rules require applicants to evaluate all available control alternatives for PSD pollutants that exceed the significance thresholds and select the best available alternative, considering the associated environmental, energy, and economic impacts. WPEA's analysis of the various control alternatives utilized EPA's preferred "top-down" methodology, which is summarized in this subsection.

2.1 BACT Top Down Process

Chapter B of the EPA's *Draft New Source Review Workshop Manual* (EPA's *Draft NSR Manual*) provides a procedure for use in establishing BACT. This procedure includes a five-step "top-down" process for considering all available control technologies from most stringent to least stringent. The most stringent control technology is considered BACT unless the applicant demonstrates, and the permitting authority agrees, that technical considerations; or energy, environmental or economic impacts, justify elimination of the most stringent technology and selection of a less stringent technology.

A summary of each of the five steps in the top-down process is described in the following text.

2.1.1 Step 1—Identify All Control Technologies

The primary objective of Step 1 is to identify all potentially applicable control options. Potentially applicable control options are those air pollution control technologies, or techniques, with a practical potential for application to the emission unit and regulated pollutant under evaluation. Potentially applicable control options are categorized as lower emitting processes/practices or add-on controls.

Based on the guidelines provided in EPA's *Draft NSR Manual* and summarized above, and utilizing the sources indicated, a comprehensive list of potentially applicable control technology options was developed for each regulated pollutant emitted from each emission unit.

2.1.2 Step 2—Eliminate Technically Infeasible Options

The objective of Step 2 is to refine the list of potentially applicable control technology options developed in Step 1 by evaluating the technical feasibility of each of the control technology options.

In accordance with EPA's *Draft NSR Manual*, control technologies that have been installed and operated successfully on the type of source under review are "demonstrated" and are considered technically feasible (EPA 1990, p. B17). For technologies that have not been demonstrated for a particular source type, EPA's *Draft NSR Manual* states that a technology is considered technically infeasible if it is not available or not applicable. Control technologies that are not available or not applicable are determined to be technically infeasible.

2.1.3 Step 3—Rank Remaining Control Technologies by Control Effectiveness

The ranking of the control options initially involves the establishment of appropriate units of emission performance. For purposes of the BACT analysis, the unit of measure used for the emissions rate of each pollutant from each emission unit was pounds per million British thermal units (lb/MMBtu).

Achievable emissions limits were established for each of the control technology options based on manufacturer's data, engineering estimates, published literature and the experience of other sources. A table was developed to rank the control technology options by their respective emissions performance from lowest to highest emissions level (highest to lowest control effectiveness). Additionally, Step 3 of the analysis also includes a listing of the energy, environmental, and economic impacts associated with each control option.

2.1.4 Step 4—Evaluate Most Effective Controls and Document Results

The purpose of Step 4 is to either confirm the suitability of the top ranked control technology option as BACT, or provide clear justification for a determination that a lower-ranked control technology option is BACT for the case under consideration. In order to establish the suitability of a control technology option, a case-by-case evaluation of the energy, environmental, and economic impacts of the control technology is performed.

The case-by-case determinations consider both beneficial and adverse direct impacts from an energy, environmental, and economic standpoint. In cases where the determination establishes that there are significant energy, environmental, and/or economic issues that would preclude the selection of the evaluated alternative as BACT, the basis for this determination is clearly documented, and the next most effective alternative is similarly evaluated. This process continues until the evaluated alternative is not rejected and is selected as BACT.

2.1.5 Step 5—Most Effective Control not Eliminated Selected as BACT

In Step 5, the highest ranked control technology not eliminated in Step 4 is selected as BACT.

The following sections present a summary of the top-down BACT analysis completed for the PC boilers. The five-step procedure described in above is summarized for each regulated pollutant applicable to the source.

2.2 Organization of This Report

2.2.1 Process of Evaluation

Because this report is intended as a summary of the control alternatives considered (and not an exact copy of WPEA's BACT analysis), the control technology evaluations presented below are organized as follows:

- Control alternatives considered.
- Control alternatives eliminated.
- Control selected. The top technology is selected except as noted. For any pollutant where the economic, environmental, or energy impacts of the top control alternative eliminate the technology from consideration, the relevant impacts are summarized.

2.3 Summary of Control Alternatives Evaluation for CO and VOC

2.3.1 Control Alternatives Considered

Carbon monoxide and VOCs are generated during the combustion process as the result of incomplete thermal oxidation of the carbon contained within the fuel. Properly designed and operated boilers typically emit low levels of CO/VOC. A listing of potential control alternatives is provided in Table 3.

TABLE 3
Summary of Control Alternatives

Control Alternatives	Description
Combustion Controls	Optimization of the design, operation, and maintenance of the furnace and combustion system is the primary mechanism available for lowering CO/VOC emissions. The furnace/combustion system design on modern PC-fired boilers provides all of the factors required to facilitate complete combustion. As a result, a properly designed furnace/combustion system is effective at limiting CO/VOC formation by maintaining the optimum furnace temperature and amount of excess oxygen.
Flares	Flares are commonly used in the control of organic-laden slipstreams with sufficient heating value. When an exhaust stream is ignited by the pilot flame at the flare tip, combustion occurs in the ambient air above the flare.
Afterburning	Afterburners convert CO/VOC into CO_2 by utilizing simple gas burners to bring the exhaust stream temperature up to 1,400°F to promote complete combustion.
Catalytic Oxidation	A catalytic oxidizer converts the CO/VOC in the combustion gases to CO_2 at temperatures ranging from 500°F to 700°F in the presence of a catalyst. Catalytic oxidizers are susceptible to fine particles suspended in the exhaust gases that can foul and poison the catalyst.
External Thermal Oxidation	ETO promotes thermal oxidation of the CO in the flue gas stream in a location external to the boiler. ETO requires heat (1,400°F to 1,600°F) and oxygen to convert CO/VOC in the flue gas to CO_2.

2.3.2 Control Alternatives Eliminated

The potentially applicable control alternatives for CO/VOC emissions identified are each evaluated for technical feasibility. Alternatives that are not available or not applicable are considered technically infeasible and are eliminated. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 4 lists the technical feasibility evaluation for each control alternative listed in Table 3.

TABLE 4
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Combustion Controls	Combustion controls are a proven technology for the reduction of CO/VOC emissions. Based on the proven success of this control strategy, combustion controls are considered a demonstrated technology for PC-fired boiler CO/VOC emissions control.	Yes
Flares	Flares have not been demonstrated for PC-fired boiler CO/VOC emission control. Limitations on the scalability of this technology preclude its commercial availability. Because the PC-fired boiler exhaust will not have sufficient heating value for flaring and because flares have not been applied for PC-fired boiler emissions control, flares are not considered an applicable technology for PC-fired boilers.	No
Afterburning	Afterburners are not demonstrated for PC-fired boiler CO/VOC control. Further, natural gas is not available at this site. The PC boilers will be tuned to maximize fuel combustion while minimizing NO_x formation, the process will result in essentially complete combustion.	No
Catalytic Oxidation	Catalytic oxidation is not a demonstrated technology for PC-fired boilers. Catalytic oxidation systems require a minimum temperature of 500°F for proper operation, dictating that the catalyst be installed upstream of the flue gas desulfurization and fabric filter systems. The particulate loading of the flue gas stream upstream of the fabric filter would be higher than the design capacity of any oxidation catalyst. Trace elements present in the coal and the combustion gases would foul the catalyst, dramatically reducing its effectiveness.	No
External Thermal Oxidation	Regenerative ETO and recuperative ETO have not been demonstrated for use on PC-fired boilers. ETO is not applicable for PC-fired boiler CO/VOC control for the same reason as afterburners.	No

2.3.3 Control Alternative Selected

Based on the analysis summarized above, combustion controls are the top control alternative. Therefore, combustion controls were selected as BACT for CO/VOC. Table 5 lists the BACT emission limits for CO/VOC.

TABLE 5
List of BACT Emission Limits for CO/VOC

Pollutant	Control Alternative Selected	BACT Emission Limit
CO	Combustion Controls	0.15 lb/MMBtu (24-hour average)
VOC	Combustion Controls	0.0036 lb/MMBtu (24-hour average)

2.4 Summary of Control Alternatives Evaluation for NO_x

2.4.1 Control Alternatives Considered

In coal-fired boilers, fuel nitrogen oxides (NO_x) generally accounts for 75 percent of all NO_x generated. Additional NO_x can be generated because of high-temperature reactions between nitrogen and oxygen in the combustion air. Factors affecting the generation of NO_x include flame temperature, residence time, quantity of excess air, and nitrogen content of the fuel.

A listing of potential control alternatives is provided in Table 6. Combinations of control alternatives were evaluated where such combinations would potentially apply.

TABLE 6
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Nitrogen is one of the elements contained in coal. The amount of nitrogen varies with the type of coal, but generally ranges from 0.5 to 2 percent (EPA 2002). Presumably, fuel NO_x emissions could be reduced by burning a coal that contains less nitrogen.
Low NO_x Burners (LNB)	LNB are designed to limit NO_x formation by controlling the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the distribution and mixing of the fuel and air.
Overfire Air (OFA)	OFA is a combustion control technology in which 5 percent to 20 percent of the total combustion air is diverted from the burners and injected through ports located above the top burner level (Srivastava, et al. 2005). OFA is generally used in conjunction with Low NO_x Burners which reduces NO_x formation.
Rotating Opposed Fire Air (ROFA)	ROFA® is a new combustion technology developed by Mobotec USA, Inc. The ROFA® design injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion.
Induced Flue Gas Recirculation (IFGR)	Induced flue gas recirculation (IFGR) recirculates boiler flue gas from the boiler outlet to the furnace here it is reintroduced into the combustion process.
Selective Catalytic Reduction (SCR)	SCR is a post-combustion NO_x reduction technology in which ammonia is added to the flue gas upstream of a catalyst bed. The ammonia and NO_x react on the surface of the catalyst, forming nitrogen (N2) and water.

TABLE 6
Summary of Control Alternatives

Control Alternative	Description
Natural Gas Reburning (NGR) + Selective Catalytic Reduction (SCR)	NGR diverts part of the main fuel heat input to locations above the main burners, thus creating a secondary combustion zone called the reburn zone. A secondary (or reburn) fuel, natural gas, is injected to produce a slightly fuel rich reburn zone. Overfire air is added above the reburn zone to complete burnout of the reburn fuel.
Fuel-Lean Gas Reburning (FLGR) + Selective Catalytic Reduction (SCR)	FLGR, also known as controlled gas injection, is a process in which careful injection and controlled mixing of natural gas into the furnace exit region reduces NO_x.
Advanced Gas Reburning (AGR) + Selective Catalytic Reduction (SCR)	AGR adds a nitrogen rich compound (typically urea or ammonia) downstream of the reburning zone. The reburning system is adjusted for somewhat lower NO_x reduction to produce free radicals that enhance the selective non-catalytic NO_x reduction.
Amine Enhanced Gas Injection (AEGI) + Selective Catalytic Reduction (SCR)	AEGI is similar to AGR, except that burn out air is not used, and the selective non-catalytic reduction reagent and reburn fuel are injected to create local, fuel-rich NO_x reduction zones in an overall fuel-lean furnace.
Hybrid Selective Reduction (HSR)	HSR is a combination of selective non-catalytic reduction (SNCR) and SCR that is designed to provide the performance of full SCR with a smaller footprint and potentially lower costs. The final emission level of an HSR system is equivalent to the level of control achieved by an SCR system.
SCONO$_x$	SCONO$_x$ uses a precious metal catalyst to simultaneously convert NO_x and CO to CO_2, H_2O, and N_2. The catalyst must be periodically removed from service for regeneration.
THERMALONO$_x$	THERMALONO$_x$ is based on the oxidation of NO to NO_2 and then dissolving the NO_2 in water. The THERMALONOx technology is intended for use with a wet flue gas desulfurization (FGD) system used for SO_2 emission control.
Electro-Catalytic Oxidation (ECO)	ECO oxidizes gaseous pollutants in a reactor. A scrubber removes NO_x, SO_2 and the oxidizer reactor products. A WESP captures the oxidized pollutants.
Pahlman Process	The Pahlman Process is a multi-pollutant control technology that simultaneously controls NO_x and SO_2. This technology is currently in the pilot stage of development, and the company operates a trailer-mounted pilot demonstration unit that can process coal-fired boiler exhaust slip streams of up to 2,000 scfm (NETL, 2007).

2.4.2 Control Alternatives Eliminated

The potentially applicable technologies for the control of NO_x emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 2.5 lists the technical feasibility evaluation for each control technology listed in Table 7.

TABLE 7
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value; coal is not sorted by nitrogen content or NO_x production potential.	No
Low NO_x Burners (LNB)	LNB are a mature technology for the reduction of NO_x formation during combustion. LNB have been demonstrated in practice and are available from numerous vendors that are willing to offer performance guarantees.	Yes
Overfire Air (OFA)	OFA is a mature technology most often utilized concurrently with the application of LNB. OFA is expected to be furnished with a new boiler regardless of other post-combustion NO_x emission reduction technologies employed. For these reasons, OFA is considered technically feasible.	Yes
Rotating Opposed Fire Air (ROFA®)	To date, ROFA® has only been installed as a retrofit technology on units firing bituminous coals. Additionally, the ROFA® technology would not be expected to provide better emissions performance than the LNB + OFA baseline, ROFA® technology is not considered further in this analysis.	No
Induced Flue Gas Recirculation (IFGR)	IFGR has not been demonstrated as a NO_x reduction technology for PC-fired boilers. IFGR is only commercially available for gas and oil-fired units. The applicability of this technology is precluded because of the technical complications associated with recirculating the volume of hot, ash-laden flue gas that is generated by a large coal-fired boiler.	No
Selective Catalytic Reduction (SCR)	SCR is a proven technology for the reduction of NO_X emissions. It has been demonstrated in similar applications to reduce NO_x emissions significantly over a range of load conditions.	Yes
Natural Gas Reburning (NGR) + Selective Catalytic Reduction (SCR)	NGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease because of lower inlet NO_x concentrations, and there is no data available to indicate that the NGR + SCR combination could achieve a lower NO_x emission rate than SCR alone. Also, installing NGR would represent additional capital and operating costs with no assurance of improved environmental performance. (Cost information is provided for NGR to establish the higher cost of the reburning technologies – Since natural gas is not currently available at the site, WPEA would have to construct approximately 90 miles of natural gas pipeline at an estimated capital cost of $73.7 million. Annual costs for natural gas are estimated at $104.9 million. Negative environmental impacts would also be expected due to construction of a 90 + mile natural gas pipeline.)	No
Fuel Lean Gas Reburning (FLGR) + Selective Catalytic Reduction (SCR)	FLGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease because of lower inlet NO_x concentrations, and there is no data available to indicate that the FLGR + SCR combination could achieve a lower NO_X emission rate than SCR alone. Also, installing FLGR would represent additional capital and operating costs with no assurance of improved environmental performance.	No
Advanced Gas Reburning (AGR) + Selective Catalytic Reduction (SCR)	AGR could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease because of lower inlet NO_x concentrations, and there is no data available to indicate that the AGR + SCR combination could achieve a lower NO_x emission rate than SCR alone. Also, installing AGR would represent additional capital and operating costs with no assurance of improved environmental performance.	No

TABLE 7
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Amine Enhanced Gas Injection (AEGI) + Selective Catalytic Reduction (SCR)	AEGI could presumably be used in conjunction with SCR. However, the control efficiency of the SCR system would decrease because of lower inlet NO_x concentrations, and there is no data available to indicate that the AEGI + SCR combination could achieve a lower NO_x emission rate than SCR alone. Also, installing AEGI would represent additional capital and operating costs with no assurance of improved environmental performance.	No
Hybrid Selective Reduction (HSR)	Because HSR involves the sequential application of SNCR and SCR, the final emission level of an HSR system is equivalent to the level of control achieved by an SCR system. WPEA is willing to accept the potentially higher cost of SCR in exchange for the demonstrated reliability of this proven technology.	No
$SCONO_x$	$SCONO_x$ is not a demonstrated technology for controlling NO_x emissions from coal-fired boilers. The manufacturer of this technology does not offer $SCONO_x$ for application to coal-fired boilers. The presence of sulfur in the flue gas has the potential to poison the $SCONO_x$ catalyst, limiting its effectiveness and its useful life.	No
$THERMALONO_x$	The poorer-than-expected results of the first commercial operation prompted the host utility to halt testing of the technology until further laboratory testing could be completed. $THERMALONO_x$ is currently in the laboratory/pilot stage of development.	No
Electro-Catalytic Oxidation (ECO)	The ECO technology is still in the pilot plant stage of development. This technology has not been demonstrated for full-scale operations.	No
Pahlman Process	The Pahlman Process has not been demonstrated beyond the pilot scale testing stage of development, this technology is not considered available.	No

2.4.3 Control Alternative Selected

LNB + OFA is compatible with SCR. Based on the analysis summarized above, the combination of LNB, OFA, and SCR was determined to be the top control option. Therefore, BACT for NO_x was determined to be the application of LNB, OFA, and SCR with a limit of 0.07 lb/MMBtu on a 24-hour rolling average basis.

2.5 Summary of Control Alternatives Evaluation for SO_2

2.5.1 Control Alternatives Considered

Sulfur Dioxide (SO_2) is generated during the combustion process as a result of the thermal oxidation of the sulfur contained in the fuel. A listing of potential control technologies is provided in Table 8.

TABLE 8
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Coal-fired boiler SO_2 emissions result from the oxidation of sulfur contained in the coal during the combustion process. Therefore, the potential for SO_2 formation can be reduced by firing coal with low sulfur content.
Coal Cleaning/Coal Refining	Coal cleaning is a process that removes this mineral ash matter from the coal by a water wash. Coal refining is a process that employs mechanical and thermal means to increase the quality of the coal by removing moisture, sulfur, nitrogen, and heavy metals.
Wet Scrubber	In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry.
Regenerable Wet Scrubber	The regenerable wet scrubber is a technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of SO_2 from the flue gas. The spent sorbent is regenerated to produce concentrated streams of sulfur compounds that can be further processed.
Spray Dryer Absorber (Dry Scrubber)	In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The by-products of the sorption and reaction are in a dry form upon leaving the system.
Circulating Dry Scrubber (CDS)	In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and SO_2.
Limestone Injection Dry Scrubbing (LIDS)	In the LIDS system, limestone is injected into the furnace and a spray dryer absorber is installed between the air heater and particulate collection device.
Furnace Sorbent Injection + Wet Scrubber Duct Sorbent Injection + Wet Scrubber	FSI/DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb SO_2. In the FSI technology, the reagent is injected directly into the furnace. In the DSI technology, the reagent is injected into the ductwork. The reaction product is collected in the downstream particulate collection device.

2.5.2 Control Alternatives Eliminated

In this step, the potentially applicable technologies for the control of SO_2 emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 9 lists the technical feasibility evaluation for each control technology listed in Table 8. Because coal selection is a feasible option for all potential add-on control technologies, coal selection was used as the base case for the impact summary.

TABLE 9
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	Coal selection is a demonstrated method for minimizing the amount of sulfur available for SO_2 formation. Low sulfur PRB, Colorado, and Utah coals are available for use at the Facility.	Yes
Coal Cleaning/Coal Refining	The coal supply for the WPES has low characteristic ash content and would not be expected to benefit significantly from coal cleaning. Coal refining is not a demonstrated technology for large-scale PRB coal combustion. Based on the lack of refined PRB coal production capacity, coal refining is not considered an available technology. Additionally, WPEA is not aware of refining being applied to Colorado or Utah bituminous coal.	No
Wet Scrubber	Wet scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Regenerable Wet Scrubber	The sodium sulfite and ammonia-based technologies have been commercially demonstrated and are available. Regenerable wet scrubbers achieve an SO_2 emissions reduction equivalent to that of a wet scrubber. EPA's Draft NSR Manual allows applicants to review only the lowest cost option if several potential options achieve an essentially identical level of performance (EPA 1990, p. B20).	No
Spray Dryer Absorber (Dry Scrubber)	Dry scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Circulating Dry Scrubber (CDS)	CDS have not been demonstrated at the 530-MW scale of the WPEA facility. Scale-up efforts for fluidized bed systems are known to be problematic and would be expected to require a significant level of effort and cost.	No
Limestone Injection Dry Scrubbing (LIDS)	LIDS is not a demonstrated technology for controlling SO_2 emissions from large-scale coal combustion. LIDS is still under development and is not commercially available for large-scale operations.	No
Furnace Sorbent Injection + Wet Scrubber Duct Sorbent Injection + Wet Scrubber	FSI/DSI could presumably be used in conjunction with a wet scrubber. However, the control efficiency of the wet scrubber would decrease because of lower inlet SO_2 concentrations, and there is no data available to indicate that the FSI/DSI + Wet Scrubber combination could achieve a lower SO_2 emission rate than a wet scrubber alone.	No

2.5.3 Impacts Associated with Wet Scrubbing

Although wet scrubbing was determined to have the highest SO_2 control efficiency, the wet scrubbing alternative was eliminated from consideration because of the associated energy, environmental, and economic impacts detailed in WPEA's PSD air permit application and summarized as follows:

1. Of particular importance is that dry scrubbing in combination with a baghouse will result in lower overall air emissions (219 tons per year lower emissions) than wet scrubbing, as shown in Table 10.

2. A wet scrubber would result in higher rates of acid emissions (HF and sulfuric acid mist) compared to a dry scrubber in combination with a baghouse. Higher rates of acid emissions would result in increased rates of acid deposition, potentially affecting terrestrial and aquatic ecosystems.

3. Water consumption for a wet scrubber would be approximately 40 percent higher than required to operate a dry scrubber. A wet scrubber system has an incremental consumption of 678 acre-feet (221,000,000 gallons) of water per year. That additional water would be capable of supporting approximately 841 additional homes (based on the average Nevada household consuming 0.8 acre-foot (262,645 gallons) of water per year) (American Water Works Association, 1996).

4. A wet scrubber would create a wastewater stream estimated to require an additional 42 acres of evaporation pond surface area.

5. A wet scrubber would use more than twice the amount of energy of a dry scrubber. A wet scrubber would demand a parasitic load of up to 34.5 MW for the Facility. This would be enough energy to provide for approximately 29,000 homes (UtiliPoint, 2007).

6. A wet scrubber would produce additional solid waste and would consume additional solid waste disposal space compared to a dry scrubber. The extra 76,018 tons per year produced by a wet scrubbed facility would consume an additional 801 acre-feet of disposal area space.

7. A wet scrubber would be more likely than a dry scrubber to emit a visible steam plume, which is considered an undesirable effect.

8. The estimated incremental cost of wet scrubbing would be in the range of incremental costs contributing to other recent decisions in favor of dry scrubbing. The incremental cost of using wet scrubber over dry would be $20,114 per ton. Based on this annualized cost, the additional cost for wet scrubbing over dry scrubbing would be $33,795,000 per year.

TABLE 10
Facility-Wide Emissions Related to SO_2 Control Options

Pollutant	Total Emissions from the PC-Fired Boilers [c] Dry Scrubber (tons per year)	Wet Scrubber (tons per year)
SO_2 [a]	4,455	2,742 [b]
H_2SO_4	164	1,124
Fluorides as HF	66	754
Efficiency Related Emissions [d]		
CO	-	134
NO_x	-	62
SO_2	-	36

TABLE 10
Facility-Wide Emissions Related to SO_2 Control Options

Pollutant	Total Emissions from the PC-Fired Boilers [c]	
	Dry Scrubber (tons per year)	Wet Scrubber (tons per year)
PM/PM_{10}	-	34
VOC	-	3
H_2SO_4	-	15
Total	4,685	4,904

[a]Assumes coal with an average sulfur content of 0.32 percent (the average of 12 PRB coal specifications obtained as the design coal basis for the Plum Point Energy Station in Osceola, Arkansas). For this coal, a dry scrubber would achieve 0.065 lb/MMBtu, and a wet scrubber is assumed to achieve 0.04 lb/MMBtu.

[b]For the emissions comparison, a conservatively low wet scrubber SO_2 emission factor of 0.04 lb/MMBtu is used, corresponding to 95 percent control with 0.32 percent sulfur coal. This low emission factor reflects NDEP's decision on the Newmont permit requiring control efficiency values as enforceable permit limits (if NDEP required 95 percent control for a wet-scrubbed system firing 0.32 percent sulfur coal, the resulting SO_2 emission limit would be 0.04 lb/MMBtu). There are currently no wet scrubber systems with permitted or proposed SO_2 BACT limits less than 0.06 lb/MMBtu. Thus, the concept of achieving 0.04 lb/MMBtu as SO_2 BACT remains speculative and is only presented here to create the most conservative comparison between the two technologies.

[c]Assumes 100 percent annual capacity factor.

[d]Efficiency-related emissions represent the additional emissions associated with having to use more fuel to compensate for the higher parasitic load from wet scrubbing. Dry scrubbing is considered the base case for efficiency related emissions.

2.5.4 Control Alternative Selected

Because wet scrubbing was eliminated from consideration during the BACT analysis because of the energy, environmental, and economic impacts summarized above, wet scrubbing is not carried forward for detailed analysis in the EIS. Dry scrubbing in combination with low sulfur coal was selected as SO_2 BACT for the PC-fired boilers. Because the SO_2 emission rate depends on the sulfur content of the coal combusted, a two-tiered SO_2 BACT limit was created:

- 0.09 lb/MMBtu for coals with greater than or equal to 0.45 percent sulfur and
- 0.065 lb/MMBtu for coals with less than 0.45 percent sulfur

2.6 Summary of Control Alternatives Evaluation for PM/PM_{10} and Lead

2.6.1 Control Alternatives Considered

Particulate matter (PM) is the general term for a mixture of solid particles and liquid droplets present in the emissions stream. PM emissions that are less than 10 microns in diameter are referred to as PM_{10}. PM and PM_{10} are emitted from coal-fired boilers as a result of the ash contained in the coal. Approximately 80 percent of the ash contained in the coal becomes fly

ash and is present in the boiler exhaust as PM and/or PM_{10}. Additionally, lead is typically contained in the particulate matter with size less than 10 microns. Therefore, the control technologies available for the control of PM/ PM_{10} emissions are the same technologies for the control of lead. A listing of potential control alternatives is provided below in Table 2.9.

TABLE 11
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Combustion of a lower ash-containing coal would result in less fly ash, hence less PM/PM_{10}. Additionally, lead emissions could be reduced by burning coals that contain less lead content.
Coal Cleaning	Coal normally contains quantities of inorganic elements, and trace levels of lead. These elements may occur in the ash-forming mineral deposits embedded within the coal. Coal cleaning is a process that removes this mineral ash matter from the coal.
Fabric Filter	A fabric filter baghouse removes particles and condensed metals (including lead) from the flue gas by drawing dust-laden flue gas and condensables through a bank of filter tubes suspended in a housing. The dust is then collected in a hopper.
Electrostatic Precipitator (ESP)	An electrostatic precipitator (ESP) removes dust and condensed metals (including lead) from the flue gas by charging the particles inductively with an electric field and then attracting the particles to highly charged collector plates, from which they are removed by a rapping system into a ash hopper.
Wet Electrostatic Precipitator (WESP)	A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP. However, with a WESP, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid.

2.6.2 Control Alternatives Eliminated

In this step, the potentially applicable control alternatives for the control of PM/PM_{10}-lead emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 12 summarizes the technical feasibility evaluation for each control alternative listed in Table 11.

TABLE 12
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value. Coal is not sorted by ash content.	No
Coal Cleaning	The coal supply for the WPES has low characteristic ash content and would not be expected to benefit significantly from coal cleaning.	No
Fabric Filter Baghouse	The fabric filter baghouse is a proven technology for the control of boiler PM/PM_{10}-lead emissions, and demonstrated in similar applications.	Yes
Electrostatic Precipitator (ESP)	The ESP is a proven technology for the control of boiler PM/ PM_{10}-lead emissions, and has been widely demonstrated in similar applications.	Yes
Wet Electrostatic Precipitator (WESP)	The WESP is a proven technology for the control of boiler PM/ PM_{10}-lead emissions. This technology has been demonstrated in similar applications	Yes

TABLE 12
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?

2.6.3 Control Alternative Selected

Based on vendor data, and recent permitting precedent; an ESP, a WESP, and a fabric filter baghouse would all be expected to achieve the same level of control: 0.015 lb/MMBtu for PM/PM_{10}, and 1.8×10^{-5} for lead. EPA's *Draft NSR Manual* allows applicants to review only the lowest cost option that achieves an identical level of performance (EPA, 1990, B20). An ESP/WESP would present additional cost because of the auxiliary power consumed. The additional power required to operate an ESP/WESP (3.62 MW), as compared to a filter baghouse would be enough energy to provide for approximately 3,042 homes (UtiliPoint, 2007). A WESP would also create a wastewater stream requiring treatment, representing additional costs and environmental impacts. Accordingly, BACT for PM/ PM_{10}-lead emissions control was determined to be the use of a fabric filter baghouse. Because the ESP and WESP alternatives were eliminated during the BACT analysis because of the equivalent level of control and associated environmental and economic impacts, the ESP and WESP alternatives are not carried forward for detailed analysis.

The BACT emissions limit for PM/PM_{10} was established as 0.015 lb/MMBtu on a 3-hour rolling average basis, and the BACT emissions limit for lead was established as 1.8×10^{-5} lb/MMBtu on a 3-hour rolling average basis.

2.7 Summary of Control Alternatives Evaluation for Fluorides

2.7.1 Control Alternatives Considered

Fluorides are emitted from coal-fired boilers because of trace concentrations of elemental fluorine and fluorine compounds in the coal. Fluorine is emitted predominantly in the gaseous form of hydrogen fluoride (HF). For the purposes of this analysis, fluorides are expressed as HF as appropriate because all emissions of fluorides from the PC boilers are expected to be in the form of HF. A summary of potential control alternatives is provided in Table 13.

TABLE 13
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Fluorine exists in trace amounts in coal deposits. Fluoride emissions could be reduced by burning coals that contained less fluorine content.
Coal Cleaning	Fluorine may occur in the ash-forming mineral deposits embedded within the coal. Coal cleaning is a process that removes this mineral ash matter from the coal after it is removed from the ground.

TABLE 13
Summary of Control Alternatives

Control Alternative	Description
Wet Scrubber	In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The HF is removed from the flue gas by sorption and reaction with the slurry.
Regenerable Wet Scrubber	The regenerable wet scrubber is a technology that uses sodium sulfite, magnesium oxide, sodium carbonate, amine, or ammonia as the sorbent for removal of SO_2 from the flue gas. The spent sorbent is regenerated to produce concentrated streams of sulfur compounds that can be further processed.
Spray Dryer Absorber (Dry Scrubber)	In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The by-products of the sorption and reaction are in a dry form upon leaving the system.
Circulating Dry Scrubber (CDS)	In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and HF.
Furnace Sorbent Injection/ Duct Sorbent Injection	DSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb HF. In the FSI technology, the reagent is injected directly into the furnace. In the DSI technology, the reagent is injected into the ductwork. The reaction product is collected in the downstream particulate collection device.

2.7.2 Control Technologies Eliminated

The potentially applicable control alternatives for HF emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 14 lists the technical feasibility evaluation for each control technology listed in Table 13.

TABLE 14
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value. Coal is not sorted by fluorine content.	No
Coal Cleaning	Coal cleaning would provide no significant benefit for the added cost and water consumption. Therefore, coal cleaning is not typically performed on PRB, Colorado, or Utah coal.	No
Wet Scrubber	Wet scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Regenerable Wet Scrubber	Regenerable wet scrubbers have been installed and operated successfully on PC boilers. Thus, regenerable wet scrubbers are considered technically feasible.	Yes
Spray Dryer Absorber (Dry Scrubber)	Dry scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes

TABLE 14
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Circulating Dry Scrubber (CDS)	CDS have not been demonstrated at the 530-MW scale of the WPEA facility. Scale-up efforts for fluidized bed systems are known to be problematic and would be expected to require a significant level of effort and cost.	No
Furnace Sorbent Injection /Duct Sorbent Injection	Although there is little operating experience supporting the effectiveness of FSI/DSI in removing HF from PC-fired boiler exhaust, FSI/DSI is considered technically feasible.	Yes

2.7.3 Control Alternative Selected

Based on EPA data (EPA, 2002), the top control alternative is a dry scrubber with fabric filter baghouse. The top control alternative was selected for HF BACT: the application of a dry scrubber and fabric filter baghouse combination with an emission limit of 9.7×10^{-4} lb/MMBtu on a 3-hour average basis.

2.8 Summary of Control Alternatives Evaluation for H_2SO_4

2.8.1 Control Alternatives Considered

The formation of H_2SO_4 occurs via two primary mechanisms. The first mechanism is the formation of liquid droplets of H_2SO_4 from the reaction of water vapor and SO_3. The second mechanism is through vapor condensation. A listing of potential control alternatives is provided in Table 15.

TABLE 15
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Coal-fired boiler H_2SO_4 emissions result from the oxidation of sulfur contained in the coal during the combustion process. Therefore, the potential for H_2O_4 formation can be reduced by firing coal with low sulfur content.
Coal Cleaning/Coal Refining	Coal cleaning is a process that removes this mineral ash matter from the coal by a water wash. Coal refining is a process that employs mechanical and thermal means to increase the quality of the coal by removing moisture, sulfur, nitrogen, and heavy metals.
Wet Scrubber	In a wet scrubber system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The H_2SO_4 is removed from the flue gas by sorption and reaction with the slurry.
Spray Dryer Absorber (Dry Scrubber)	In a dry scrubber system, lime, the reagent, is slurried with water and sprayed into the flue gas stream in an absorber vessel. The by-products of the sorption and reaction are in a dry form upon leaving the system.
Circulating Dry Scrubber (CDS)	In a CDS, flue gas, coal ash, and lime sorbent form a fluidized bed in an absorber vessel. The flue gas is humidified in the vessel to aid the absorption reactions between the lime and H_2SO_4.

TABLE 15
Summary of Control Alternatives

Control Alternative	Description
Limestone Injection Dry Scrubbing (LIDS)	In the LIDS system, limestone is injected into the furnace and a spray dryer absorber is installed between the air heater and particulate collection device.
Furnace Sorbent Injection/ Duct Sorbent Injection + Wet Scrubber	DSI/FSI is a once-through dry technology that utilizes dry lime or limestone as the reagent to absorb H_2SO_4. FSI injects the reagent directly into the furnace. In the DSI technology, the reagent is injected into the ductwork.
Wet Electrostatic Precipitator (WESP)	A wet electrostatic precipitator (WESP) operates in the same three-step process as a dry ESP. However, the removal of particles from the collecting electrodes is accomplished by washing the collection surface using liquid.

2.8.2 Control Alternatives Eliminated

The potentially applicable control alternatives for H_2SO_4 emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 16 lists the technical feasibility evaluation for each control technology listed in Table 15.

TABLE 16
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	Coal selection is a demonstrated method for minimizing the amount of sulfur available for H_2SO_4 formation. Low sulfur PRB, Colorado, and Utah coals are available for use at the Facility.	Yes
Coal Cleaning/ Coal Refining	The coal supply for the WPES has low characteristic ash content and would not be expected to benefit significantly from coal cleaning. Based on the lack of refined PRB coal production capacity, coal refining is not considered an available technology. Additionally, WPEA is not aware of refining being applied to Colorado or Utah bituminous coal.	No
Wet Scrubber	Wet scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Regenerable Wet Scrubber	The sodium sulfite and ammonia-based technologies have been commercially demonstrated and are available. Regenerable wet scrubbers achieve an SO_2 emissions reduction equivalent to that of a wet scrubber. EPA's Draft NSR Manual allows applicants to review only the lowest option if several potential options achieve an essentially identical level of performance (EPA, 1990, B20).	No
Spray Dryer Absorber (Dry Scrubber)	Dry scrubbers have been demonstrated on coal-fired boilers and are commercially available from a number of suppliers.	Yes
Circulating Dry Scrubber (CDS)	CDS have not been demonstrated at the 530-MW scale of the WPEA facility. Scale-up efforts for fluidized bed systems are known to be problematic and would be expected to require a significant level of effort and cost.	No
Limestone Injection Dry	LIDS is not a demonstrated technology for controlling H_2SO_4 emissions from large-scale coal combustion. LIDS is still under	No

TABLE 16
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Scrubbing (LIDS)	development and is not commercially available for large-scale operations.	
Furnace Sorbent Injection/ Duct Sorbent Injection	Although there is little operating experience supporting the effectiveness of FSI/DSI in removing H_2SO_4 from PC-fired boiler exhaust, FSI/DSI is considered technically feasible.	Yes
Wet Electrostatic Precipitator (WESP)	WESP systems have been shown to remove H_2SO_4 mist from exhaust streams and are considered technically feasible.	Yes

2.8.3 Impacts Summary

Because WESP technology is compatible with both wet and dry scrubbing, this technology was evaluated in conjunction with both wet and dry scrubbers. The top three control alternatives, in terms of H_2SO_4 removal efficiency, were determined to be the following:

1. Dry Scrubbing + WESP
2. Wet Scrubbing + WESP
3. Dry Scrubbing

Both dry scrubbing and wet scrubbing in combination with WESP were eliminated from consideration because of the associated energy, environmental, and economic impacts detailed in WPEA's PSD air permit application and summarized below.

2.8.3.1 Energy Impacts

Compared to a dry scrubber alone, a WESP would result in a 33 percent higher parasitic load, and the combination of wet scrubbing + WESP would result in a parasitic load over 300 percent higher. To put these parasitic values in perspective, the WPES would have to combust an additional 19,027 tons of coal per year to compensate for auxiliary power consumed by the WESP. For a wet scrubber + WESP, an additional 142,017 tons of coal would be required. This additional fuel consumption would result in additional air emissions and train traffic.

2.8.3.2 Environmental Impacts

Water Consumption—Compared to a dry scrubber alone, a WESP would result in 11 percent higher water usage, and the combination of wet scrubbing + WESP would result in 51 percent higher water usage. This increased water usage equates to enough water to support 224 homes and 1,065 homes respectively.

Wastewater Production—While a dry scrubber alone would not produce a wastewater stream, a wet scrubber would produce a wastewater stream containing concentrations of dissolved and suspended chemicals potentially requiring specialized water handling and treatment equipment. In addition, water treatment might be required for the wet scrubber plant's wastewater prior to disposal in the evaporation pond to remove heavy metals

(which are 15 percent to 25 percent higher for a plant with wet scrubbing than a plant with dry scrubbing) and chlorides (which are 547 percent higher for a plant with wet scrubbing than with a plant with dry scrubbing). A WESP would create a blowdown stream that must be chemically neutralized prior to discharge. The neutralized blowdown stream would have to be discharged and treated in accordance with the applicable regulations.

Solid Waste Production—A wet scrubber would produce additional solid waste and would consume an additional solid waste disposal space of 801 acre-feet/year.

Blowdown—A WESP would create a blowdown stream that must be chemically neutralized prior to discharge. The neutralized blowdown stream must then be discharged and treated in accordance with the applicable regulations.

2.8.3.3 Economic Impacts

Compared to a dry scrubber alone, the incremental cost (the cost of achieving the additional emissions reductions) of adding a WESP would be \$175,000 per ton of H_2SO_4 removed, and the incremental cost of wet scrubbing + WESP would be \$524,000 per ton of H_2SO_4 removed. Annualized, the incremental costs would be \$6,956,000 and \$18,142,000 respectively.

2.8.3.4 Summary

Based on the negative energy, environmental, and economic impacts summarized above, the dry scrubbing + WESP and wet scrubbing + WESP alternatives were eliminated from further consideration in the BACT analysis. Because the combinations of dry scrubbing + WESP and wet scrubbing + WESP were eliminated during the BACT analysis, these alternatives are not carried forward for detailed analysis. The top remaining control alternative is dry scrubbing.

2.8.4 Control Alternative Selected

Based on the analysis summarized above, dry scrubbing was selected as H_2SO_4 BACT for the PC-fired boilers. Additionally, the selection of low-sulfur coal (as determined above in the analysis for SO_2) will help to minimize emissions of H_2SO_4. The BACT emission limit is 0.0034 lb/MMBtu on a 3-hour average.

(which are 15 percent to 25 percent higher for a plant with wet scrubbing than a plant with dry scrubbing) and chlorides (which are 200 percent higher for a plant with wet scrubbing than a plant with dry scrubbing). A WESP would create a blowdown stream that must be [illegible] to be discharged and [illegible]

Solid Waste Production—A [illegible] would produce additional solid waste and would contribute an additional [illegible]

Blowdown—A WESP would create a blowdown stream that must be chemically treated [illegible] in accordance with the [illegible]

2.8.3.3 Economic Impacts

Compared to a dry scrubber alone, the incremental cost effectiveness of achieving the [illegible] emissions reduction of adding a WESP would be [illegible] Annualized, the [illegible]

2.8.3.4 Summary

Based on the negative energy, environmental, and economic impacts [illegible] the dry scrubbing + WESP [illegible] further [illegible] WESP and [illegible] alternative is [illegible]

2.8.4 Control Alternative Selected

Based on the [illegible] BACT [illegible] 0.0034 [illegible]

3.0 Hazardous Air Pollutants

As discussed in Sections 1.1, HAPs can be divided into several categories, including organic compounds, acid gases, and metals. Many of the control strategies implemented for the PSD Pollutants, discussed in Section 2, have a collateral affect for controlling HAPs. These are discussed below.

Evaluations of the available control alternatives for organic compounds, acid gases, and metals are provided in detail below.

3.1 Summary of Control Alternatives Evaluation for Organic HAPs

Organic HAPs emitted from coal combustion include compounds listed in Section 1.2.1. The control strategies for these pollutants are the same as those utilized for VOCs. For a detailed evaluation of the control alternatives applicable to organic HAPs, please see the evaluation for VOC control alternatives in Section 2.3. Based on evaluation of the feasibility of the available control techniques for VOCs, combustion controls were selected as the preferred control alternative for organic HAPs.

3.2 Summary of Control Alternatives Evaluation for Acid Gases HAPs

Acid gas HAPs emitted from coal combustion include HCl and HF. The control strategies for these pollutants are identical. Because emissions of fluorides (as HF) triggered the significance threshold in Table 1.1, a BACT analysis was conducted for fluorides as HF (see Section 2.7 above). Based on evaluation of the feasibility of the available control techniques and the outcome of the BACT analysis for HF, the combination of a dry scrubber with a fabric filter baghouse was selected as the preferred control alternative for acid gases.

3.3 Summary of Control Alternatives Evaluation for Metals HAPs

3.3.1 Class 1 and 2 Metals HAPs

EPA's *Compilation of Air Pollutant Emission Factors* ("AP-42") lists three classes of metals that are emitted from coal combustion (Refer to Section 1.2.3 for a description of each class). For Class 1 and 2 metals, the air emission control strategies are the same as those utilized for particulate matter. Thus, for a detailed evaluation of the control alternatives applicable to these classes of metals please refer to the evaluation for particulate control alternatives in Section 2.6 above. Based on evaluation of the feasibility of the available control techniques

and the outcome of the BACT analysis for particulate, a fabric filter baghouse was selected as the preferred control alternative for Class 1 and Class 2 metals.

3.3.2 Class 3 Metals HAPs (Mercury)

A detailed evaluation of the control alternatives for Class 3 metals is included in the following text. While the evaluation below applies to both mercury and selenium, the discussion focuses specifically on mercury because mercury emissions are considered the primary pollutant of concern for the Class 3 metals group.

3.3.3 Control Alternatives Considered (Mercury)

Mercury is a naturally occurring element found in the earth's crust. As a natural fuel extracted from the earth's crust, coal contains trace levels of mercury. During the coal combustion process, mercury emissions may be generated in oxidized, elemental, or particulate form. A listing of potential control alternatives is provided in Table 17.

It should be noted that while some mercury may be captured collaterally with the controls designed for criteria pollutants, further emissions reductions can be achieved via the use of add-on controls.

TABLE 17
Summary of Control Alternatives

Control Alternative	Description
Coal Selection	Mercury emissions could be reduced by burning coals that contain less mercury content.
Coal Cleaning/Coal Refining	Coal cleaning is a process that removes this mineral ash matter from the coal by a water wash. Coal refining is a process that employs mechanical and thermal means to increase the quality of the coal by removing moisture, sulfur, nitrogen, and heavy metals.
Co-Benefit Control	The control alternatives WPEA has selected to control NO_x, SO_x and PM/ PM_{10} have been shown to reduce mercury emissions. This "native removal" of mercury by the control alternatives selected for criteria pollutants is known as "co-benefit" control.
Halogenated Activated Carbon Injection	Halogenated activated carbon sorbent is injected into the flue gas. The sorbent attracts and binds the mercury to its surface, and is then captured in a fabric filter baghouse.

3.3.4 Control Alternatives Eliminated (Mercury)

In this step, the potentially applicable control alternatives for the control of mercury emissions identified are each evaluated for technical feasibility. Alternatives eliminated at this stage of the analysis are not carried forward for detailed analysis. Table 18 summarizes the technical feasibility evaluation for each control alternative listed in Table 17.

TABLE 18
Elimination of Technically Infeasible Options

Control Alternative	Technical Feasibility Evaluation	Technically Feasible?
Coal Selection	The type of coal used in a boiler is selected based on fuel characteristics such as sulfur content and heating value. Coal is not sorted by mercury content.	No
Coal Cleaning/Coal Refining	The coal supply for the WPES has low characteristic mercury content and would not be expected to benefit significantly from coal cleaning. Based on the lack of refined PRB coal production capacity, coal refining is not considered an available technology. Additionally, WPEA is not aware of refining being applied to Colorado or Utah bituminous coal.	No
Co-Benefit Control Alternatives	Co-benefit control alternatives have been proven to control boiler mercury emissions, and demonstrated in similar applications.	Yes
Halogenated Activated Carbon Injection (AVI)	There is extensive operating experience with activated carbon injection for waste incinerators. This technology is now commercially available for the power industry and is considered technically feasible.	Yes

3.3.5 Control Alternative Selected (Mercury)

Based on the analysis above, the combination of co-benefit control alternatives and halogenated activated carbon injection was determined to be the preferred control option for mercury and other Class 3 metals. The emissions limit for mercury was established as 0.00002 lb/Mwh on a rolling 12-month averaging period.

4.0 Greenhouse Gas Emissions

As stated in Section 1.4, greenhouse gases are components in the atmosphere that contribute to the greenhouse effect. CO_2 is considered the primary greenhouse gas of concern for fossil fuel combustion. Although CO_2 is not a regulated pollutant, it has recently been brought to the forefront in greenhouse gas discussions as a possible contributor to climate change.

Because add-on CO_2 removal technologies are not currently available (see Appendix E of this FEIS for additional information), the only means for minimizing CO_2 emissions are as follows:

- Select efficient generation technologies; and
- Increase electrical generation by emissions control systems that minimize parasitic load (electricity that is used within the power plant and not exported).

Because of advances in PC boiler technology, the WPEA facility will be 10 percent to 15 percent more efficient as compared to older PC power plants. The decreased fuel consumption associated with the WPEA facility's efficiencies results in decreased CO_2 emissions relative to the existing generation fleet. Additionally, CO_2 emissions are further minimized because of the lower parasitic load of the control alternatives (dry scrubber vs. wet scrubber) selected for the WPEA facility. The selection of dry scrubbing at the WPES results in CO_2 emissions 180,000 tons per year lower than a wet-scrubbed facility.

4.1 Future Planning

Future technological or regulatory developments may facilitate the feasibility of carbon capture systems. Retrofitting pollution control equipment at existing power facilities is difficult due the lack of spaces available between the boiler and stack. WPEA has set aside approximately 20 acres adjacent to the PC-fired boiler stacks where carbon capture equipment could be installed after this technology becomes technically feasible and commercially viable. For additional information on the capture-ready nature of the proposed Station, see Appendices E and F of this FEIS.

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Appendix E

Carbon Capture and Sequestration

Report

Carbon Capture and Sequestration

Prepared for

U.S. Bureau of Land Management

Ely Field Office, Nevada

Contents

Background

Future changes in market conditions or regulations on carbon dioxide (CO_2) emissions could provide an incentive for U.S. power plants to capture and sequester emissions of CO_2. In the context of a pulverized coal-fired (PC-fired) power plant, "capture" of CO_2 refers to the removal of a portion of the CO_2 present in the exhaust stream (Carbon capture and sequestration for integrated gasification combined cycle (IGCC) facilities is discussed in detail in a separate report). CO_2 that is "sequestered" would be permanently stored in a manner that would prevent the CO_2 from reaching the atmosphere.

This report summarizes the state of carbon capture and sequestration (CCS) technology and evaluates the alternatives that could potentially be implemented for CCS at the White Pine Energy Station (WPES).

CCS Technologies

CCS technologies have not reached a mature stage of development in the energy industry and are not currently available for deployment on full-scale operations at PC-fired power plants. However, the U.S. Department of Energy (DOE) is taking a lead role in developing the technologies via its Carbon Sequestration Program. The DOE's Carbon Sequestration Program is implemented by the National Energy Technology Laboratory (NETL) with the intention of developing the fundamental and supporting technologies that will allow CCS to become an effective and economically viable option for reducing CO_2 emissions. The goal of the Carbon Sequestration Program is to develop CCS technology that can achieve 90 percent CO_2 capture with 99 percent storage permanence at less than a 10 percent increase in the cost of energy services. The DOE estimates that large-scale systems capable of achieving these goals will be able to come online as early as 2020 (DOE, 2007a). The National Coal Council estimates that CCS technologies will become commercially available within the next 15 years and that commercial maturity may require an additional decade (National Coal Council, 2007).

The details of the CCS technologies most likely to become applicable for PC-fired power plants are summarized in the following subsections, based on information provided in the DOE's report, "Carbon Sequestration Technology Roadmap and Program Plan 2007" (the "Carbon Sequestration Roadmap"). A copy of the Carbon Sequestration Roadmap is attached for reference. It should be noted that the various technologies described below are in the research and development stage for PC-fired boilers and are not yet considered mature technologies for full-scale operations.

Post-Combustion CO_2 Capture

The exhaust from a PC-fired boiler consists primarily of nitrogen and CO_2. Absorbers utilizing amine (an amine is an organic compound containing a nitrogen atom bound with carbon and either zero, one, or two hydrogen atoms) or chilled ammonia are one potential method for removing CO_2 from PC-boiler exhaust. An amine or chilled ammonia absorber applied to a PC-fired boiler would operate as follows:

1. Exhaust gas from the PC-fired boiler is routed through an emission control system to remove nitrogen oxides (NO_x), SO_2, particulate matter, and mercury
2. The exhaust gas is fed to an absorber where the CO_2 reacts with an amine or chilled ammonia solvent and is absorbed
3. The "scrubbed" exhaust stream, containing primarily nitrogen, is vented to the atmosphere through an exhaust stack
4. The amine or chilled ammonia solution from the absorber is sent to a "stripping" column where heat is applied, releasing the CO_2. The CO_2 is then compressed into a liquid state and stored temporarily prior to sequestration.

Separating CO_2 from this flue gas stream is challenging for the following reasons:

- CO_2 is present at dilute concentrations and at low pressure, dictating that a high volume of gas be treated.
- Trace impurities (particulate matter, SO_2, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
- Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system.

To date, the use of absorption processes in PC-fired power plants has been restricted to slipstream (a fraction of an exhaust stream captured for study) applications, and no definitive analysis exists as to the actual costs for a full-scale capture plant. While actual costs are unknown, DOE currently estimates that a new bituminous PC-fired plant with carbon capture would require a capital cost 85 percent higher than that of a new bituminous PC-fired plant without capture (see DOE, 2007b). The WPES will use subbituminous, not bituminous coal; thus, these cost estimates are not directly applicable to the WPES.

Oxy-Fuel Combustion

The objective of pulverized coal oxygen-fired (or "oxy-fuel") combustion is to combust coal in an enriched oxygen environment using pure oxygen diluted with recycled CO_2 or water. Under these conditions, the primary products of combustion are CO_2 and water. The CO_2 can be captured by condensing the water in the exhaust stream and compressing the CO_2 for storage and sequestration. The primary advantage of the oxy-fuel combustion strategy is that add-on scrubbers are not required to separate CO_2 since the exhaust stream is a lower-volume water/CO_2 stream.

The oxy-fuel combustion concept utilizes air separation to provide an enriched oxygen environment for combusting the coal. Oxygen is typically produced using low-temperature (cryogenic) air separation, but novel oxygen separation techniques, such as ion transport membranes and chemical looping systems, are being developed to reduce costs. Oxy-fuel combustion offers several additional benefits, as determined through laboratory testing and systems analysis:

- A 60 to 70 percent reduction in NO_x emissions compared to uncontrolled air-fired combustion, mainly due to flue gas recycle, but also from reduced thermal NO_x levels due to lower available nitrogen.
- Increased mercury removal compared to uncontrolled air-fired combustion. Boiler tests of oxy-fuel combustion using Powder River Basin (PRB) coal resulted in increased oxidation of mercury, facilitating downstream mercury removal.
- Applicability to new and existing coal-fired power plants—The key process principles involved in oxy-fuel combustion have been demonstrated commercially (including air separation and flue gas recycle).

While the key process principles in oxy-fuel combustion (that is, air separation and flue gas recycle) have been demonstrated separately, oxy-fuel combustion has not been implemented on full-scale PC-fired systems. Plans for pilot facilities have been announced, including a 30-MW facility in Germany and a 24-MW facility in Canada (Katzer et al., 2007); however, oxy-fuel combustion technology remains unavailable for full-scale commercial implementation at this time.

Carbon Capture Research

The DOE The is pursuing research for improving existing CO_2 capture systems and also exploring new carbon capture technologies. The most likely options currently identifiable for separation and capture include:

- Absorption (chemical and physical)
- Adsorption (physical and chemical)
- Low-temperature distillation
- Gas separation membranes
- Mineralization and biomineralization

The DOE feels that the opportunities for significant cost reductions exist since very little research and development has been devoted to CO_2 capture and separation technologies.

Geologic Sequestration

Geologic sequestration involves the injection of CO_2 into underground reservoirs that have the ability to securely contain it over long periods of time. The primary objective of DOE-sponsored research is to develop technologies to cost-effectively store and monitor CO_2 in geologic formations. Accomplishing this involves improved understanding of CO_2 flow and trapping within the reservoir and the development and deployment of technologies such as simulation models and monitoring systems. Experience gained from carbon sequestration field tests will facilitate the development of best practice manuals to ensure that sequestration does not impair the geologic integrity of underground reservoirs, thus assuring secured and environmentally acceptable CO_2 storage.

DOE-sponsored research is concentrated on five types of geologic formations, each presenting unique challenges and opportunities. These formations include oil and gas reservoirs, deep saline formations, un-mineable coal seams, oil and gas rich organic shales, and basalts.

Due to their prevalence worldwide, saline formations may present the highest CO_2 sequestration capacity among the various geologic formation types. There is already one example of demonstrated commercial-scale sequestration in a saline formation. In 1996, prompted by the Norwegian tax on carbon dioxide, the oil company Statoil began taking unwanted carbon dioxide from the Sleipner West field in the Norwegian North Sea and storing it 1,000 meters beneath the seabed in a saline aquifer reservoir. Since 1996, about 1 million metric tons of carbon dioxide per year has been injected into the Utsira saline aquifer (DOE, 2007c).

DOE's carbon sequestration atlas suggests that deep saline formations may be present in White Pine County to some extent. Saline formations are composed of porous rock saturated with brine and capped by one or more regionally extensive impermeable rock formations enabling trapping of injected CO_2. Compared to coal seams or oil and gas reservoirs, saline formations are more common and offer the added benefits of greater proximity, higher CO_2 storage capacity, and fewer existing well penetrations. On the other hand, much less is known about the potential of saline formations to store and immobilize CO_2 since each aquifer is unique and not all aquifers will be suitable for sequestration. Additional research will be needed to understand the potential for deep saline formations to store captured CO_2 in White Pine County and elsewhere.

Viability of CCS Technologies for the WPES

As discussed above, the various CCS technologies potentially applicable to PC-fired power plants have not yet reached a commercially mature stage of development. Additional research and full-scale operating experience will be needed over the coming decades to demonstrate the technology as viable. Thus, CCS technologies are not considered available at this time for the White Pine Energy Station.

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Attachment

Carbon Sequestration Technology Roadmap and Program Plan 2007

U.S. Department of Energy • Office of Fossil Energy
National Energy Technology Laboratory

Carbon Sequestration Technology *Roadmap* and Program Plan

2007

Ensuring the Future of Fossil Energy Systems through the Successful Deployment of Carbon Capture and Storage Technologies

NETL

Table of Contents

I. Message to Stakeholders

Economic growth is closely tied to energy availability and consumption, particularly lower-cost fossil fuels. The use of these fossil fuels results in the release of carbon dioxide (CO_2), which is widely believed to contribute to global climate change. Balancing the economic value of fossil fuels with the environmental concerns associated with fossil fuel use is a difficult challenge. To retain fossil fuels as a viable world energy source, carbon capture and storage (CCS) technologies must play a central role. By cost-effectively capturing CO_2 before it is emitted to the atmosphere and then permanently storing or sequestering it, fossil fuels can be used in a carbon constrained world and without constraining economic growth.

The global nature of CO_2 emissions is illustrated in Figure 1 and shows that total world CO_2 emissions are expected to increase significantly by 2030. Absent binding constraints, CO_2 emissions in Organization for Economic Cooperation and Development (OECD) countries—which include the United States, most of Europe, Australia, Korea, New Zealand and Japan—are expected to increase at about 1.1 percent per year through 2030. CO_2 emissions in non-OECD countries outside Europe and Eurasia—including fossil fuel-rich China and India—are expected to grow at 3.0 percent per year, in line with strong economic growth. As a point of reference, the U.S. emitted about 6 billion metric tons of CO_2 in 2005, accounting for about 22 percent of total world CO_2 emissions.

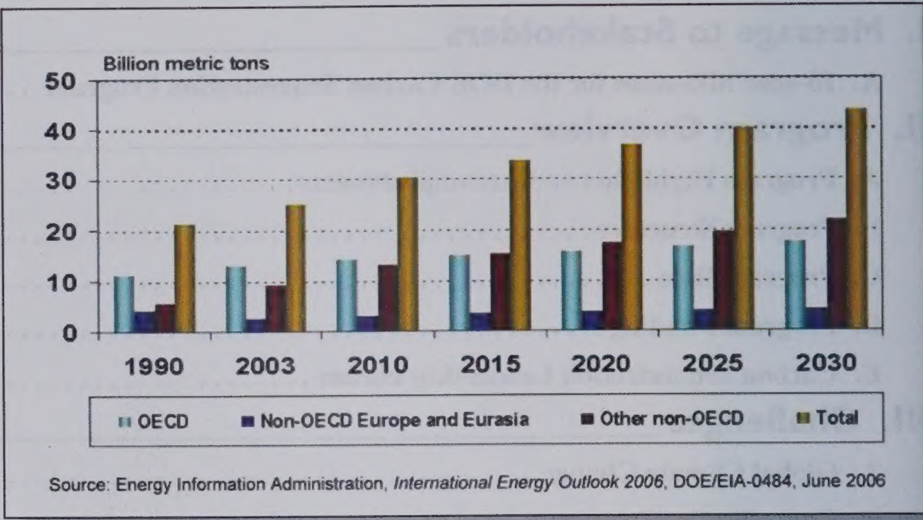


Figure 1. World CO_2 Emissions by Region

On a global scale, CCS technologies have the potential to reduce overall climate change mitigation costs and increase flexibility in reducing greenhouse gas (GHG) emissions. According to the 2005 report, *Carbon Dioxide Capture and Storage,* by the Intergovernmental Panel on Climate Change (IPCC), the application of CCS technologies in GHG mitigation portfolios could reduce the costs of stabilizing CO_2 concentrations in the atmosphere by 30 percent or more compared to scenarios where CCS technologies are not deployed. Furthermore, a particularly beneficial aspect of certain CCS technologies is that their component parts – carbon capture, transportation, and storage – can utilize technologies adapted from other commercial industries, enhancing the availability and cost competitiveness of CCS technologies as viable mitigation options.

The Global Energy Technology Strategy Program (GTSP) – a public and private sector research collaboration comprised of scientists from Battelle, the U.S. Department of Energy (DOE), Pacific Northwest National Laboratory (PNNL), and the Joint Global Change Research Institute (a partnership between PNNL and the University of Maryland) – has identified near-term, medium-term, and long-term benefits associated with CCS. In the near term, CCS technologies will allow many industries – including electricity generation, refining, chemical production, and steel and cement manufacturing – to chart a viable path forward into a carbon-constrained world. In the medium term, CCS technologies will facilitate a smoother transition of the global economy to a low GHG emissions future. In the long term, CCS will make valuable commodities like electricity and hydrogen cheaper than they would be if such technologies were not available.

DOE is taking a leadership role in the development of CCS technologies. Through its Carbon Sequestration Program (Program) – managed within the Office of Fossil Energy (FE) and implemented by the National Energy Technology Laboratory (NETL) – DOE is

developing both core and supporting technologies through which CCS will become an effective and economically viable option for reducing CO_2 emissions. The Program works in concert with other programs within FE that are developing technologies integral to coal-fueled power generation with carbon capture: advanced integrated gasification combined cycle (IGCC), advanced turbines, fuel cells, and advanced research. Successful research and development (R&D) will enable carbon control technologies to overcome the various technical, economic, and social challenges, including cost-effective CO_2 capture, long-term stability (permanence) of CO_2 in underground formations, monitoring and verification, integration with power generation systems, and public acceptance.

The overall goal of the Carbon Sequestration Program is to develop, by 2012, fossil fuel conversion systems that achieve 90 percent CO_2 capture with 99 percent storage permanence at less than a 10 percent increase in the cost of energy services. Reaching this goal requires an integrated research, development, and deployment program linking fundamental advances in CCS to practical advances in technologies amenable to extended commercial use. The technologies developed in this Program will also serve as test components in the FutureGen Initiative, aimed at building the first power plant in the world to integrate permanent carbon storage with coal-to-energy conversion and hydrogen production.

A. 10-year Milestone for the DOE Carbon Sequestration Program

The year 2007 marks the 10-year anniversary of the DOE's Carbon Sequestration Program. Launched in 1997 as a small-scale research effort to ascertain the technical viability of CCS, the Program has grown into a multi-faceted research, development, and deployment initiative that aims to provide the means by which fossil fuels can continue to be used for power generation in a carbon-constrained world. The first 10 years have significantly advanced the knowledge base pertaining to CO_2 separation, geologic and terrestrial storage, regulations and permitting, and process economics. Much work remains, however, to enable the large-scale deployment of CCS technologies. In particular, extended field tests are required to fully characterize potential storage sites and demonstrate the long-term storage of sequestered carbon to achieve cost-effective integration with power plant systems. Looking forward, it is also important to recognize CCS as more than just an end-of-process emissions control technology. CCS technologies represent critical elements in the entire energy supply picture, providing CO_2 capture and storage solutions that will enable sustained fossil fuel conversion and offer a resource recovery pathway that will facilitate greater recovery of domestic oil, natural gas, and coalbed methane.

This document describes the Technology Roadmap and Program Plan that will guide the Carbon Sequestration Program in 2007 and beyond. An overview of the Program and the key accomplishments in its 10-year history are presented as well as the challenges confronting deployment and successful commercialization of carbon sequestration technologies. The research pathways that will be used to achieve Program goals and information on key contacts and web links related to the Program are included.

This document is intended to be a valuable tool in engaging interested stakeholders. We invite readers to contact any of the persons listed on the inside back cover with comments, concerns, or suggestions.

II. Program Overview

The DOE's Carbon Sequestration Program leverages applied research with field demonstrations to assess the technical and economic viability of carbon capture and storage as a GHG mitigation option.

A. Program Highlights and Accomplishments

Since its inception 10 years ago, the Program has been moving CCS technology forward to enable its cost-effective use in meeting any future GHG emissions reduction requirements. The first decade has significantly advanced the knowledge base pertaining to CO_2 separation, geologic and terrestrial sequestration, regulations and permitting, and process economics.

The Program is a true government success story. What began as an idea has resulted in international support of CCS as a leading mitigation option for reducing GHG emissions to the atmosphere. Major Program accomplishments over its 10-year life include:

- *Carbon Sequestration Atlas.* The *Carbon Sequestration Atlas of the United States and Canada* – developed by NETL, the Regional Carbon Sequestration Partnerships (RCSPs), and the National Carbon Sequestration Database and Geographical Information System (NATCARB) – contains information on stationary sources for CO_2 emissions, geologic formations with sequestration potential, and terrestrial ecosystems with potential for enhanced carbon uptake, all referenced to their geographic location to enable matching sources and sequestration sites. An interactive version of the Atlas is available through the NATCARB website (www.natcarb.org). The Atlas can be downloaded at http://www.netl.doe.gov/publications/carbon_seq/atlas/index.html.

- *CO_2 Capture.* The Program has conducted research into solvent, sorbent, membrane, and oxy-combustion systems that, upon successful development, will be capable of capturing greater than 90 percent of the flue gas CO_2 at a significant cost reduction when compared to state-of-the-art, amine-based capture systems. Through research and systems analysis over the past years, potential cost reductions of 30-45 percent have been identified for the capture of CO_2. In addition, ionic liquid membranes and absorbents are being developed for capture of CO_2 from power plants. Ionic liquid membranes have been developed at NETL for pre-combustion applications that surpass polymers in terms of CO_2 selectivity and permeability at elevated temperatures. In related DOE-funded academic research, significant progress has been made in developing ionic liquid absorbents for post-combustion applications that show increasing breakthrough potential for more cost effective capture of CO_2 from flue gas.

- *CO_2 Storage.* Program efforts in geologic and terrestrial CO_2 storage have led to a better understanding of sequestration potential and the ability to characterize capillary forces that immobilize CO_2 in the pore spaces of a formation – also known as residual CO_2 trapping – in CO_2 fate and transport models. Furthermore, the Program has been a leader in efforts to enhance terrestrial ecosystems as carbon sequestration sites and to calibrate models for quantifying the amount of carbon stored.

- *Monitoring, Mitigation, and Verification (MM&V).* Field projects have demonstrated the ability to "map" CO_2 injected into an underground formation at a much higher resolution than previously anticipated and confirmed the ability of perfluorocarbon tracers to track CO_2 movement through a reservoir. DOE-sponsored research has also led to the development of the U-Tube sampler, which was developed for and successfully deployed at the Frio test site in Texas. This novel tool is used to obtain geochemical samples of both the water and gas portions of downhole samples at *in situ* pressure. The data collected from this tool has led to a better understanding of the coupled hydrogeochemical conditions affecting CO_2 storage in brine filled formations.

- *Systems Analysis.* NETL's Office of Systems, Analysis, and Planning (OSAP) has conducted innovative assessments of CO_2 capture and separations processes. The OSAP work in this area has increased understanding of the

issues surrounding integration of CO_2 capture systems with different fuel conversion systems, leading to the identification of improvement opportunities with the potential to significantly reduce costs. Two recently completed systems analyses are documented in the following reports: *CO_2 Capture from Existing Coal-Fired Power Plants* and *Cost and Performance Baseline for Fossil Energy Plants.* (Reports at: http://www.netl.doe.gov/technologies/carbon_seq/Resources/Analysis/)

B. Program Structure

The Carbon Sequestration Program encompasses two main elements: *Core R&D* and *Demonstration and Deployment*. Figure 2 shows how these elements are linked. The Core R&D element converts technology needs in several focus areas into technology solutions that can then be demonstrated and deployed in the field. Lessons learned from the field tests are fed back to the Core R&D element to guide future research and development.

Core R&D involves laboratory and pilot-scale research aimed at developing new technologies and new systems for GHG mitigation. The Core R&D portfolio includes cost-shared, industry-led technology development projects, research grants, and research conducted through NETL's Office of Research and Development (ORD). The Core R&D effort encompasses five focus areas: CO_2 capture; carbon storage; monitoring, mitigation, and verification; non-CO_2 greenhouse gas control; and breakthrough concepts.

The first three Core R&D research areas track the life cycle of a CCS system: CO_2 is first captured, then it is stored (sequestered) or converted to a benign or useful carbon-based product, and finally it is monitored to ensure that it remains stored, with appropriate mitigation actions taken as needed. The fourth category, non-CO_2 greenhouse gas control, primarily involves the capture and reuse of methane emissions from energy production and conversion systems such as the capture and use of coal mine ventilation air methane. The fifth area, breakthrough concepts, targets novel concepts with a high degree of technical uncertainty and those with the potential to expand the applicability of CCS beyond conventional stationary source emissions. Promising breakthrough

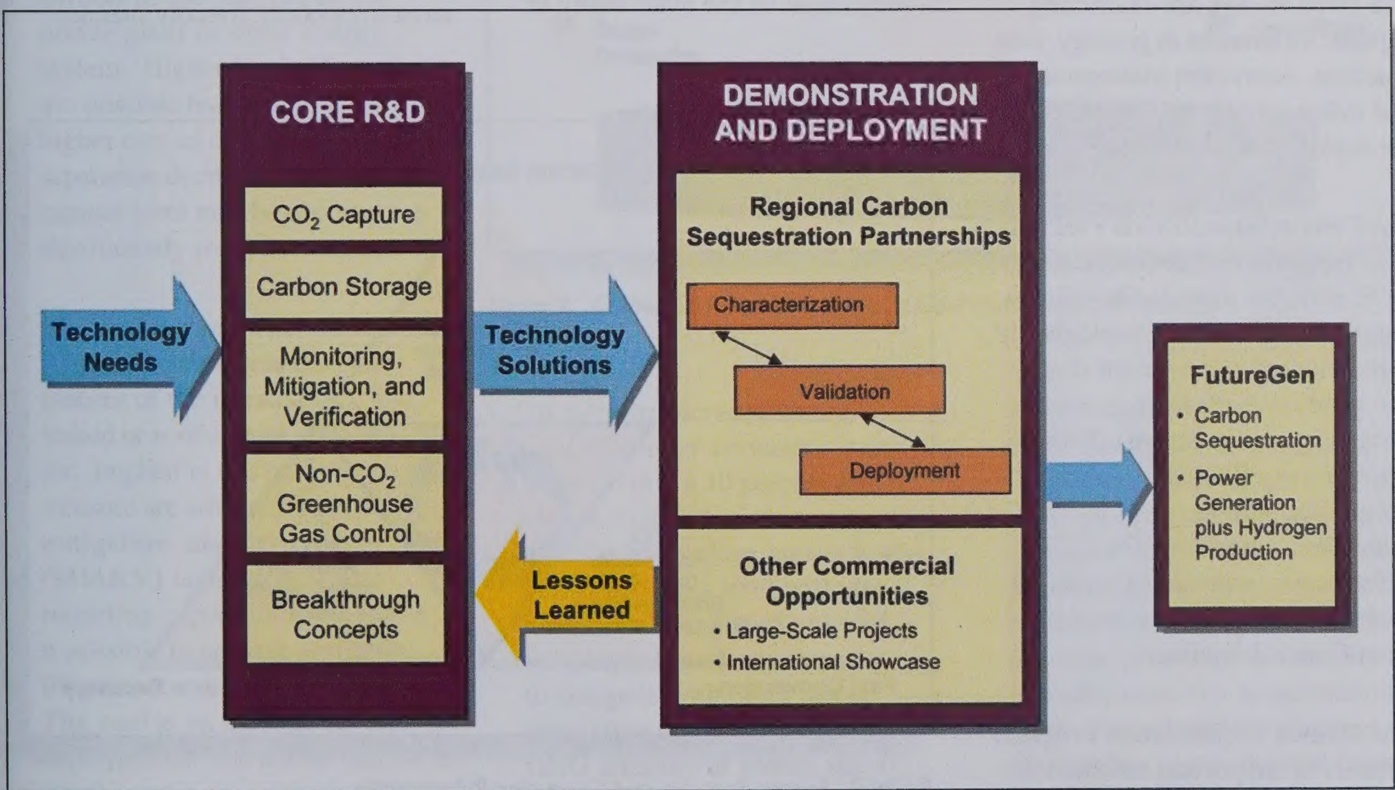


Figure 2. U.S. DOE Carbon Sequestration Technology Development

concepts being pursued include ionic liquids and microporous metal organic frameworks (MOFs) for capturing CO_2.

The Demonstration and Deployment element of the Carbon Sequestration Program is designed to demonstrate the viability of CCS technologies at a scale large enough to overcome real and perceived infrastructure challenges. Technologies will be tested in the field to identify and eliminate technical and economic barriers to commercialization. Such an effort is necessary to ensure that organizations are prepared to act if future global climate change policies require large-scale deployment of sequestration technology.

The largest component of the Demonstration and Deployment element is the Regional Carbon Sequestration Partnerships Program. The seven RCSPs are examining regional differences in geology, land practices, ecosystem management, and industrial activity that can affect the deployment of CCS technologies.

The Carbon Sequestration Program also supports FutureGen, a key DOE initiative aimed at building a highly efficient and technologically sophisticated power plant that can produce both hydrogen and electricity while capturing and sequestering CO_2 emissions. FutureGen will serve as a full-scale field laboratory for CCS technologies, providing a venue for evaluating technologies emerging from Core R&D efforts.

The Carbon Sequestration Program consists of supporting mechanisms performing systems analyses and economic modeling of potential new CO_2 capture processes to identify issues with their integration into full-scale power plants. The Program also participates in cross-cutting studies to model future national energy scenarios incorporating carbon sequestration. Finally, the Program collaborates with other U.S. government agencies with overlapping responsibilities and works with the international community through its membership in organizations such as the Carbon Sequestration Leadership Forum (CSLF).

C. Program Role

Figure 3 illustrates the unique role that CCS could play in future energy supply networks. The long-term viability of various fuel conversion pathways – including pulverized coal (PC) combustion, integrated gasification combined-cycle, biomass gasification, and coal-to-liquids – may hinge on the availability of cost-effective CCS technologies. However, carbon capture and subsurface injection represents more than just an end-of-process emissions control technology. These technologies could provide additional value by facilitating the recovery of several subsurface resources, including oil, natural gas, and coalbed methane.

Currently, in the absence of regulations limiting or taxing carbon emissions, the private sector has little incentive to develop and deploy commercial CCS technologies. However, through cost-shared R&D, the Federal government has a role to play in ensuring the availability of cost-effective technologies for capturing and sequestering CO_2 from fossil fuel use. Commercial availability of CCS technology provides public benefits in the form of the continued use of cost-effective fossil fuels in an environmentally friendly manner.

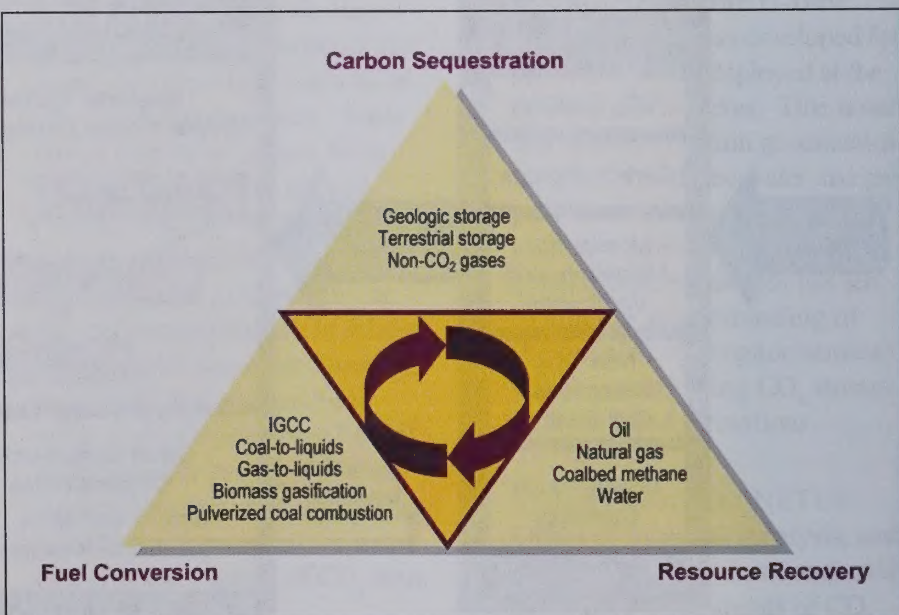


Figure 3. Energy Recovery and Conversion Relationships

As a technology and a research discipline, carbon sequestration is in its infancy. To guide the Carbon Sequestration Program through this early development period, DOE established the following initial technology goal: "To develop, by 2012, fossil fuel conversion systems that offer 90 percent CO_2 capture with 99 percent storage permanence at less than a 10 percent increase in the cost of energy services."

Figure 4. Carbon Sequestration Program Goal and Research Pathways

By simultaneously exploring a number of related research pathways, the many challenges confronting carbon sequestration can be overcome, enabling the Program to achieve this ambitious goal. R&D progress along each of the research pathways shown in Figure 4 will be necessary.

- *90 percent CO_2 capture*: The amount of CO_2 captured represents 90 percent of the carbon in the fuel fed to the power plant or other energy system. Higher levels of capture are possible but at significantly higher cost as driving forces for separation decrease. A 90 percent capture level may be necessary to significantly reduce emissions.

- *99 percent storage permanence*: After 100 years, less than one percent of the injected CO_2 has leaked or is otherwise unaccounted for. Implied in this performance measure are advanced monitoring, mitigation, and verification (MM&V) technologies and modeling capabilities that make it possible to achieve and prove 99 percent storage permanence. The goal is an average for all deployments. The test for success is whether projects can garner credits for 99 percent of injected CO_2.

- *10 percent increase in the cost of energy services*: It is believed that a 10 percent cost of electricity (COE) increase would significantly reduce impact to the economy. This level will also enable fossil fuel systems with CO_2 capture and sequestration to compete with other power generation options to reduce the GHG intensity of energy supply, including wind, biomass, and nuclear power. For the electricity supply sector, the 10 percent COE increase target is based on plant gate cost from a newly constructed power plant with capital recovery. The baseline for determining the 10 percent COE increase is the competitive cost of power generation at the time of deployment of a sequestration plant. For calculation purposes, the baseline cost is derived from the DOE Energy Information Administration (EIA) Annual

Energy Outlook projection for the average generation cost of electricity from the utility sector. The cost of CO_2 capture and storage includes parasitic power requirements, CO_2 compression, pipeline transport of 50 miles, and injection into a saline formation. Revenues from CO_2 sales for enhanced oil recovery (EOR), enhanced gas recovery (EGR), and enhanced coalbed methane (ECBM) recovery are not credited against the cost of CO_2 capture. Net reductions in the cost of criteria pollutant control are included.

- *By 2012:* The Program seeks to have pilot-scale unit operation performance results from a combination of CO_2 capture, MM&V, and storage system components such that, when integrated into a systems analysis framework, would collectively meet the above goals. Accounting for the lag associated with pre-large-scale validation and design and construction of large-scale systems, projects that meet the Program goal will result in large-scale units that come on-line around 2020.

For an evolving technology Program such as carbon sequestration, this initial Program goal represents a near-term opportunity to gauge Program progress and success. Longer-term goals are important to further explore the capabilities and potential of carbon sequestration. Figure 5 summarizes important accomplishments in the Program history and also lists future Program milestones. Additional milestones will be added as lessons learned from the Demonstration and Deployment element are fed back to the Core R&D element to guide future efforts.

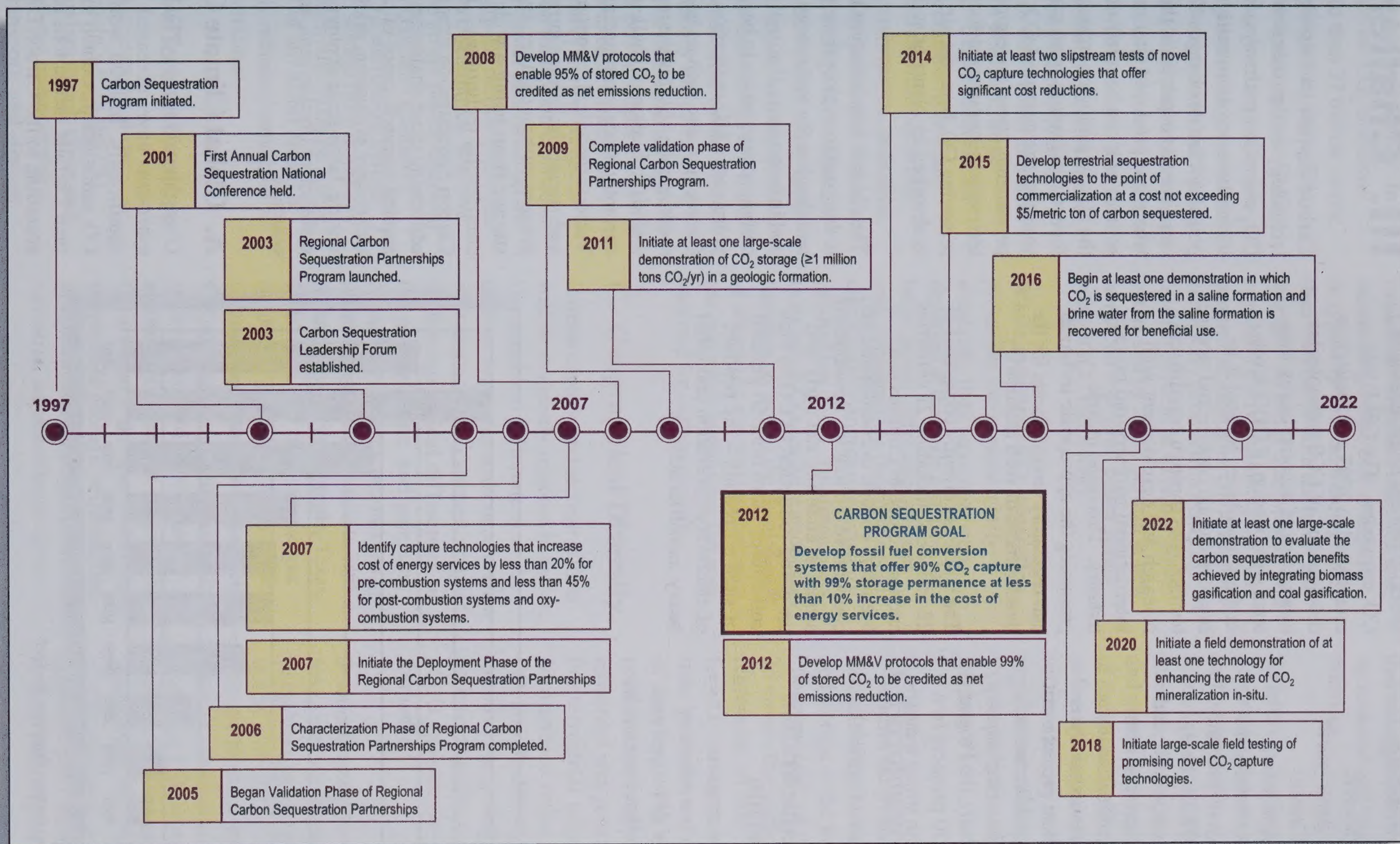


Figure 5. Carbon Sequestration Program Milestones and Goals

D. Program Funding

Translating the research, development, and deployment activities for the Carbon Sequestration Program into public benefits will continue to require effective use of Program funds (Figure 6). This is being achieved through cooperative and collaborative relationships, both domestically and internationally: competitive solicitations; analysis and project evaluation; project merit reviews; proactive public outreach and education; and an emphasis on cost-sharing. Currently, the Program funds more than 70 projects in a diverse portfolio with strong industry support that is evident by the average 31 percent cost share of projects.

E. Carbon Sequestration Leadership Forum

The Carbon Sequestration Leadership Forum is a voluntary climate initiative of developed and developing nations that accounts for about 75 percent of all manmade CO_2 emissions. The CSLF was established in 2003 and focuses on development of CCS technologies as a means of accomplishing long-term stabilization of GHG levels in the atmosphere. Its goal is to improve carbon capture and storage technologies through coordinated research and development with international partners and private industry. This could include promoting the appropriate technical, and regulatory environments for the development of such technology.

The CSLF is currently comprised of 22 members, including 21 countries and the European Commission. Members engage in coordinated and cooperative technology development aimed at enabling the early and on-going reduction of CO_2 which constitutes more than 60 percent of such emissions – the product of electricity generation and other heavy industrial activity.

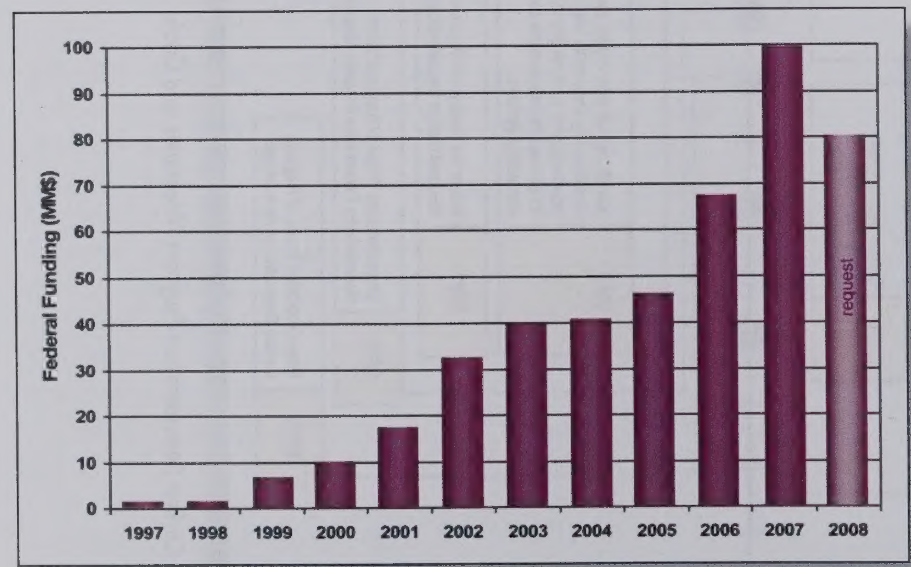


Figure 6. DOE Sequestration Program Budget

III. Challenges

Carbon capture and storage technology encompasses two main CO_2 reduction pathways, both of which have a role in mitigating potential climate change. The CO_2 can either be captured at the point where it is produced (stationary source) or it can be removed from the air. In geologic sequestration focused on capture from stationary sources, the captured CO_2 is permanently stored underground. In terrestrial sequestration focused on removing CO_2 from the air, the CO_2 is absorbed by plants or soils.

The Carbon Sequestration Program is designed to explore these pathways and develop the technology base and infrastructure that will enable carbon sequestration to become a prominent GHG mitigation option. Common to any such technology roadmapping effort is the recognition and identification of challenges that currently hinder commercialization. Various technical, economic, and social challenges currently prevent carbon capture and storage from being a widely used commercial technology. The Carbon Sequestration Program is addressing these challenges through applied research, proof-of-concept technology evaluation, pilot-scale testing, large-scale deployment, stakeholder involvement, and public outreach.

A. Global Climate Change

Over the past century, GHG emissions have increased significantly. In 1900, worldwide CO_2 emissions amounted to less than 2 billion metric tons per year, according to the Carbon Dioxide

Information Analysis Center. In 2004, worldwide CO_2 emissions totaled more than 27 billion metric tons, according to the EIA. The concern is that atmospheric GHG accumulations in excess of levels required to sustain the greenhouse effect introduce an external forcing factor leading to global temperature increases.

Reducing potential global climate change through atmospheric reductions in GHG concentrations represents a complex, large-scale effort. Carbon dioxide, for example, is emitted from many different sectors: transportation, residential, commercial, industrial, and electricity generation. Carbon capture and storage is not equally applicable or economically viable across these sectors and would likely represent just one element of a multi-faceted approach that would include energy efficiency improvements, greater use of renewable energy and nuclear power, migration to less carbon-intensive fuels, and enhancement of various types of sequestration for carbon emissions. Because the power generation sector emits the largest fraction of CO_2 in most industrial countries, however, and because power plants represent a large, concentrated stationary source of CO_2 emissions, carbon capture and storage from stationary power plants would likely be a core component of any effort aimed at significantly reducing atmospheric CO_2 concentrations.

B. Cost-effective Capture

For geologic sequestration applications in which the CO_2 is stored underground, there are three main cost components: capture, transport, and storage (which encompasses injection and monitoring). The cost of capture is typically several times greater than the cost of both transport and storage. In today's economic and regulatory environment, carbon capture technologies could increase electricity production costs by 60-100 percent at existing power plants and by 25-50 percent at new advanced coal-fired power plants using IGCC technology.

While industrial CO_2 separation processes are commercially available, they have not been deployed at the scale required for large power plant applications and, consequently, their use could significantly increase electricity production costs. Improvements to existing CO_2 capture processes, therefore, as well as the development of alternative capture technologies, are important in reducing the costs incurred for carbon capture.

C. Geographical Diversity

Carbon capture and storage efforts will be inherently regional in nature. Geographical differences in the number, type, size, and concentration of stationary GHG sources, coupled with geographical differences in the number, type, and potential capacity of sequestration sites, dictate a regional approach to carbon management. For example, Texas, Oklahoma, and other oil and gas producing states may focus carbon management practices on capturing CO_2 and injecting it into producing oil and gas fields to enhance recovery. Conversely, states in the Great Plains and Upper Midwest may supplement geologic sequestration projects at remote power plants with terrestrial sequestration projects that enhance carbon storage using agricultural and forest management practices.

To address the importance of geographical diversity in addressing carbon management issues, DOE is funding seven RCSPs that coordinate research, development, deployment, and outreach in a particular region of the country. These RCSPs will define and implement the technology, infrastructure, standards, and regulations necessary to promote CO_2 sequestration in their respective Regions.

D. Permanence

One challenge facing carbon capture and storage is the long-term fate or "permanence" of the stored CO_2. To ensure that carbon sequestration represents an effective pathway for CO_2 management, permanence must be confirmed at a high level of accuracy. The concept of permanence is applicable to both terrestrial and geologic sequestration. For terrestrial sequestration, permanence refers to the fate of CO_2 absorbed by plants and stored in soils. For geologic sequestration, permanence refers to the retention of CO_2 in underground geologic formations.

Scientific analysis supports the long-term storage value attributed to carbon sequestration. As stated in the 2005 IPCC special report, *Carbon Dioxide Capture and Storage*, observations and analysis of current CO_2 storage sites, natural systems, engineering systems, and models indicate that the amount of CO_2 retained in appropriately selected and managed reservoirs is very likely (probability of

90-99 percent) to exceed 99 percent over 100 years and is likely (probability of 66-90 percent) to exceed 99 percent over 1,000 years. Moreover, the potential for leakage is expected to decrease over time as other mechanisms provide additional trapping.

E. Monitoring, Mitigation, and Verification

Closely related to permanence is the issue of monitoring, mitigation, and verification. The ultimate success of carbon capture and storage projects will hinge on the ability to measure the amount of CO_2 stored at a particular site, the ability to confirm that the stored CO_2 is not harming the host ecosystem, and the ability to effectively mitigate any impacts associated with a CO_2 leakage.

As with permanence, MM&V is applicable to both terrestrial and geologic sequestration. Terrestrial MM&V must overcome difficulties in assessing carbon storage in large ecosystems (such as forests) and in gauging carbon storage potential in various types of soils. Geologic MM&V must contend with challenges spanning the movement of CO_2 in geologic reservoirs, the effect of various physical and chemical forces on the CO_2 plume, leak detection, and the development of robust mitigation techniques that can respond to a variety of potential leakage events.

F. Integration and Long-term Performance

A number of the technological elements associated with carbon capture and storage are proven, but there has been no demonstrated long-term performance at large industrial sites integrating carbon capture, transportation, and final storage. Much of the knowledge base pertaining to carbon capture and storage has been derived from the oil and natural gas industries, where CO_2 has been injected for over 30 years for oil recovery and the incremental storage cost is small. Broader implementation is required, particularly in the power generation industry, but such commercialization is not likely absent emission regulations, incentives, or government funding.

Long-term integrated testing and validation is necessary for technical, economic, and regulatory reasons. From a technical perspective, the ability to separate a CO_2 stream from the power plant flue gas stream, compress it for pipeline delivery, and sustain delivery at pressures adequate to ensure dependable injectivity and reservoir permeability must be confirmed. From an economic perspective, the costs associated with CCS must be quantified in greater detail to encourage investment and ensure cost recovery. From a regulatory perspective, long-term operating data must be collected to ensure that CO_2 transportation systems, injection wells, and storage reservoirs are properly regulated to safeguard the environment and public health.

G. Permitting and Liability

Because carbon capture and storage remains a relatively young technology – particularly in terms of projects in the field – a number of permitting and liability issues are still evolving. With respect to permitting, CO_2 injection and monitoring wells will have to comply with state and Federal regulations. In early 2006, the U.S. Environmental Protection Agency (EPA) concluded that geologic sequestration of CO_2 through well injection met the definition of "underground injection" in the Safe Drinking Water Act. As a result, underground sources of drinking water must be protected from potential endangerment attributed to carbon sequestration pilot projects, most likely through the issuance of underground injection control permits. Currently, injection wells for carbon sequestration with EOR or EGR are being permitted as Class II injection wells (wells that inject waste fluids associated with the production of oil and natural gas). However, injection wells for all other carbon sequestration projects are being permitted as Class V experimental technology wells (wells that are not included in any other class and inject non-hazardous fluids). To ensure that Agency efforts are coordinated and communicated effectively, DOE participates in quarterly meetings at a high management level with EPA. In addition, both DOE and the RCSPs were involved with providing comments for EPA's first Underground Injection Control program guidance related to permitting initial pilot projects as experimental technology wells, giving regulatory agencies enhanced flexibility in expediting these projects.

Access and liability issues represent another uncertain, evolving challenge. In many states, land rights are held separate from mineral rights, potentially complicating sequestration projects aimed at secondary resource recovery. Gaining access to attractive underground storage sites may prove to be difficult in some cases.

Liability concerns primarily center on which entity or group of entities will be responsible for the CO_2 stored underground after injection is completed. Since the stored CO_2 will conceivably remain underground indefinitely, lines of responsibility must be defined that can track potential damage or impacts to a particular leak. Federal and state agencies, insurance companies, the CO_2 producer, the sequestration site operator, and the landowner may all be involved in determining the chain of custody, developing appropriate bonding mechanisms, remediating any problems, and providing long-term monitoring. Illinois and Texas have recently addressed these liability issues as they relate to clean coal projects. Legislation pending in Illinois would provide adequate liability protection and permitting certainty to facilitate the siting of a FutureGen project in the state. While the FutureGen plant operator would retain title to and any liabilities associated with the pre-injection CO_2, the state would accept title to and any liabilities associated with the sequestered gas. Legislation enacted in Texas specifies that the owner or operator of a clean coal project will retain liability for the CO_2 generated before it is captured but indicates that the state will accept title to the CO_2 captured by the power plant and may make it available for sale or for injection into a geologic formation for permanent storage.

H. Public Acceptance

The public is generally unfamiliar with CCS and the large role it might play in the reduction of GHG emissions. Education and outreach efforts are required to dispel misconceptions, outline opportunities and challenges, and invite feedback pertaining to implementation mechanisms.

Public support is critical to the success of research and commercialization efforts; more importantly, public disapproval is very difficult to overcome. It is imperative, therefore, that the relevant government and private entities engage the public to explain the technology and address environmental, health, and safety concerns as they arise. Public outreach activities conducted by the RCSP coordinators have included: development and utilization of a suite of educational and outreach tools to communicate with national, regional, and local audiences, policymakers, and stakeholders on the subject of carbon sequestration including a carbon sequestration video for general and non-technical audiences; focus groups to gauge public knowledge and perceptions of carbon sequestration; town hall-style meetings to inform and educate about sequestration; risk communication workshops; and hundreds of carbon sequestration posters, presentations, and other outreach materials for public dissemination.

I. Infrastructure

If carbon capture and storage is widely deployed to control CO_2 emissions, significant infrastructure investments will be required, particularly for geologic sequestration. Stationary source CO_2 emitters like coal-fired power plants may have to invest in a host of non-core assets, including carbon separation systems, CO_2 pipelines, drilling rigs, injection systems, and monitoring networks. Beyond the capital investment required, emitters may face resource competition for the equipment and personnel needed to install, operate, and maintain these systems. Access to drilling rigs, for example, could become a key issue if the oil and natural gas sectors continue aggressive domestic drilling campaigns.

During the large-scale carbon sequestration test projects planned for the next 10 years, an additional infrastructure challenge involves the supply of sufficient CO_2 to enable long-term deployment and evaluation. While huge quantities of CO_2 are theoretically available from power plant sources, separation and supply of this CO_2 for the carbon storage deployments projects is unlikely because of the expense involved in separating the CO_2 in the absence of CO_2 emission regulations and/or because of the uncertain reliability associated with utility-scale CO_2 separation systems. In most cases, the CO_2 required for the deployment projects will be supplied from natural sources or from industrial processes that produce a relatively pure CO_2 stream as a by-product. Securing sufficient quantities of CO_2 from these sources is a key requirement.

IV. Technology Development Efforts

The Carbon Sequestration Program is developing a portfolio of technologies with great potential to reduce GHG emissions. The primary concentration of this high priority Program is on dramatically lowering the cost and energy requirements of pre- and post-combustion CO_2 capture. The goal is to have a technology portfolio by 2012 for safe, cost-effective, and long-term carbon mitigation, management, and storage, which will lead to substantial market penetration after 2012. In the long-term, the Program is expected to contribute significantly to the President's goal of developing technologies to substantially reduce GHG emissions.

A. Core R&D

The Program's Core R&D element encompasses five focus areas: CO_2 Capture; Carbon Storage; Monitoring, Mitigation, and Verification; Non-CO_2 Greenhouse Gas Control; and Breakthrough Concepts. Research activities are conducted through an array of internal and external funding mechanisms, spanning laboratory-scale research through pilot-scale deployment. Focus area research converts technology needs related to CCS into technology solutions ready for larger-scale testing and deployment.

1. CO_2 Capture

Carbon sequestration begins with the separation and capture of CO_2 from power plant flue gas and other stationary sources. At present, this process is both costly and energy intensive; analysis shows that CO_2 capture accounts for the majority of the cost of the CCS system. Therefore, R&D goals within the Program's CO_2 Capture focus area are aimed at improving the efficiency and reducing the costs of capturing CO_2 emissions from coal-fired power generating plants, as shown in Figure 7.

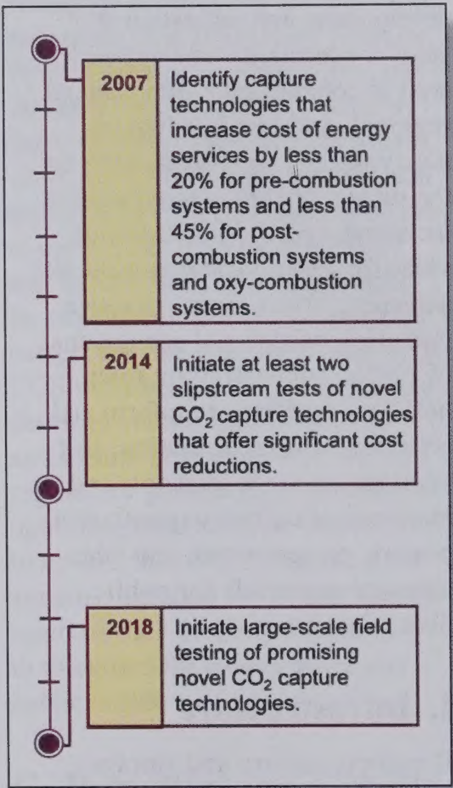


Figure 7. Capture Goals

The Program currently funds a large number of laboratory-scale and pilot-scale research projects involving solvents, sorbents, membranes, and oxygen combustion systems (oxy-combustion). Efforts are focused on systems for capturing CO_2 from coal-fired power plants since they are the largest stationary sources of CO_2, although the technologies developed will be applicable to natural-gas-fired power plants and industrial CO_2 sources as well.

Figure 8 highlights the critical challenges and R&D pathways related to CO_2 capture. The pathways include both advanced fossil fuel conversion technologies and CO_2 capture technologies, recognizing the strong synergy that exists between the two areas. The Program's CO_2 capture research is being conducted in close coordination with research on advanced, higher-efficiency power generation and fossil fuel conversion.

CO_2 capture systems may be divided into three categories: post-combustion, pre-combustion, and oxy-combustion.

Post-combustion. Post-combustion CO_2 capture is primarily applicable to conventional coal-fired power generation, but may also be applied to gas-fired generation using combustion turbines. In a typical coal-fired power generation system, fuel is burned with air in a boiler to produce steam; the steam drives a turbine to generate electricity, as shown in Figure 9. The boiler exhaust, or flue gas, consists mostly of nitrogen (N_2) and CO_2. Separating CO_2 from this flue gas stream is challenging for several reasons:

- CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure

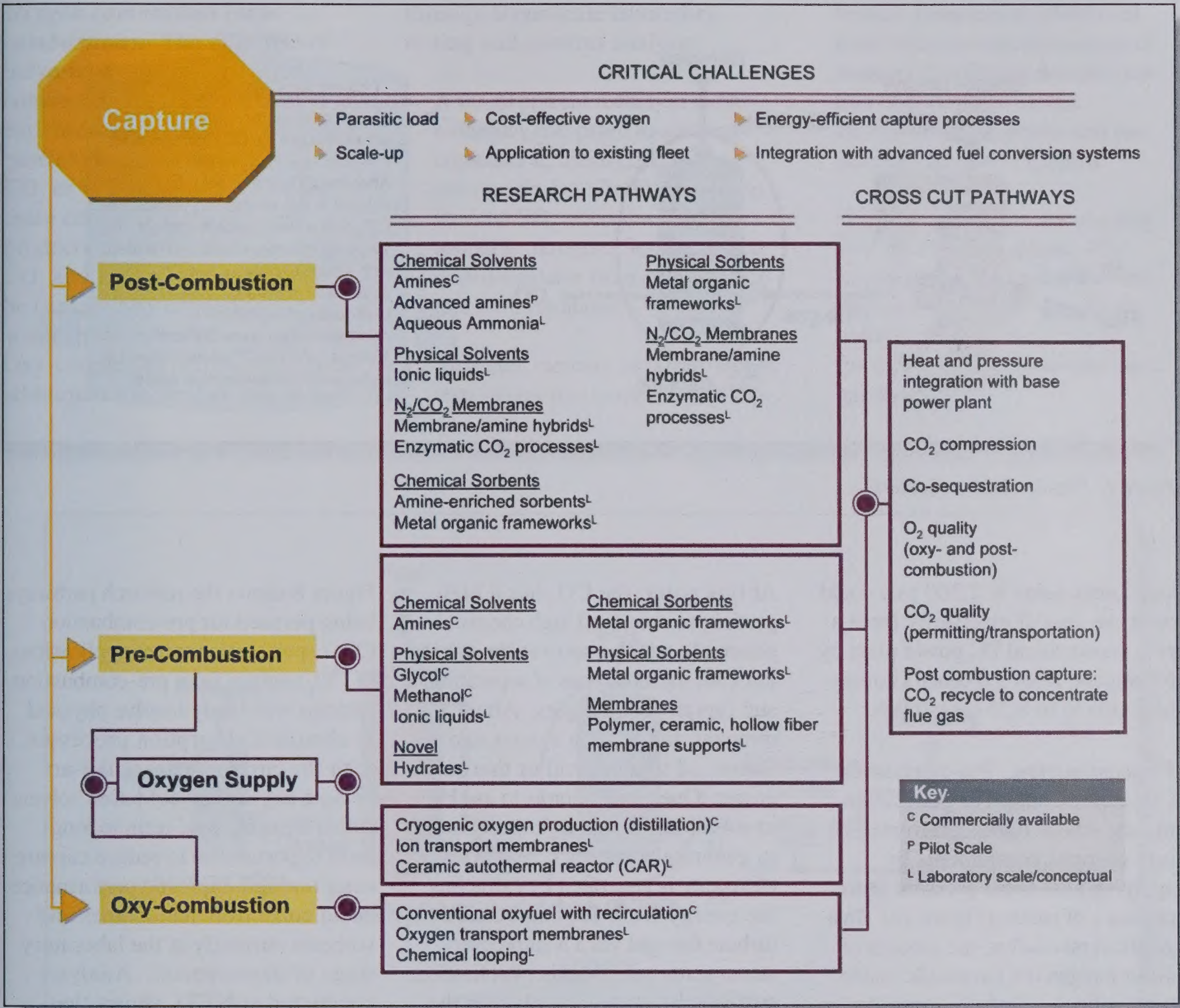


Figure 8. CO_2 Capture Pathways

(15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.

- Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
- Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system.

Absorption processes based on chemical solvents such as amines, as described in Figure 9, have been developed and deployed commercially in certain industries. To date, however, their use in PC power plants has been restricted to slipstream applications, and no definitive analysis exists as to the actual costs for a full-scale capture plant. Preliminary analysis conducted at NETL indicates that CO_2 capture via amine scrubbing

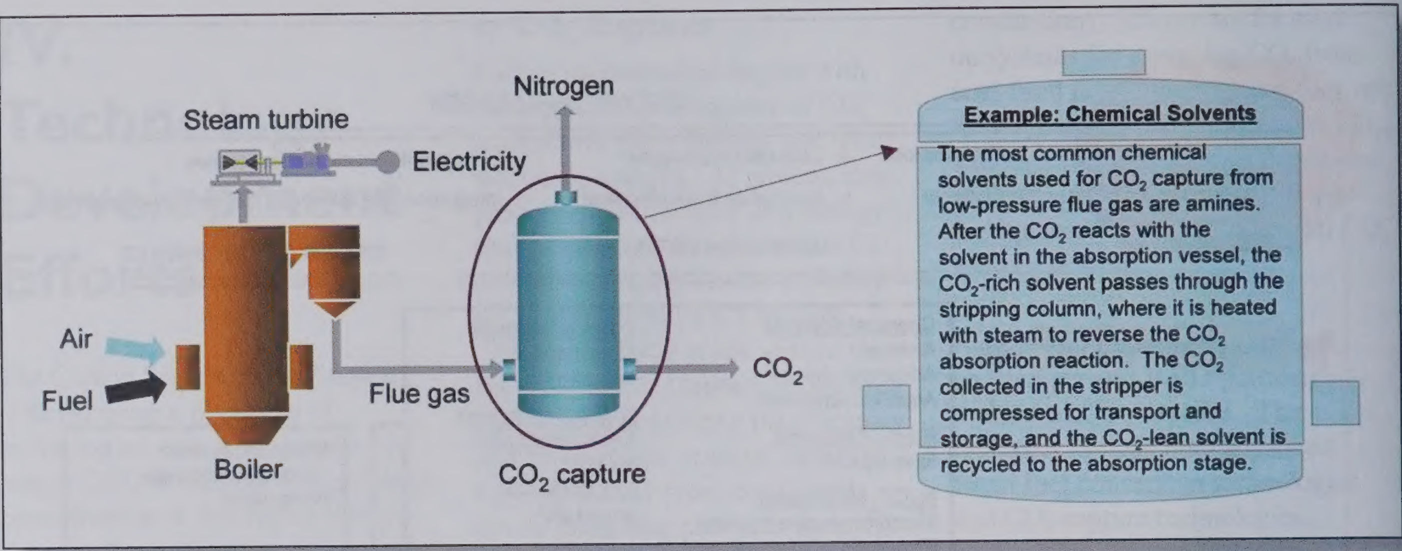


Figure 9. Post-Combustion Capture

and compression to 2,200 psia could raise the cost of electricity from a new supercritical PC power plant by 65 percent, from 5.0 cents/kilowatt-hour (kWh) to 8.25 cents/kWh.

Pre-combustion. Pre-combustion CO_2 capture relates to gasification plants, where fuel is converted into gaseous components by applying heat under pressure in the presence of steam (Figure 10). In a gasification reactor, the amount of air or oxygen (O_2) available inside the gasifier is carefully controlled so that only a portion of the fuel burns completely. This "partial oxidation" process provides the heat necessary to chemically decompose the fuel and produce synthesis gas (syngas), which is composed of hydrogen (H_2), carbon monoxide (CO) and minor amounts of other gaseous constituents. The syngas is then processed in a water-gas-shift (WGS) reactor, which converts the CO to CO_2 and increases the CO_2 and H_2 mole concentrations to 40 percent and 55 percent, respectively, in the syngas stream.

At this point, the CO_2 has a high partial pressure (and high chemical potential), which improves the driving force for various types of separation and capture technologies. After CO_2 removal, the H_2 rich syngas can be converted to electrical or thermal power. One application is to use H_2 as a fuel in a combustion turbine to generate electricity. Additional electricity is generated by extracting the energy from the combustion turbine flue gas via a heat recovery steam generator. Another application, currently being developed under the DOE Fuel Cell Program, is to utilize the H_2 to power fuel cells with the intent of significantly raising overall plant efficiency. Because CO_2 is present at much higher concentrations in syngas than in post-combustion flue gas, CO_2 capture should be less expensive for pre-combustion capture than for post-combustion capture. Currently, however, there are few gasification plants in full-scale operation and capital costs are higher than for PC plants.

Figure 8 shows the research pathways being pursued for pre-combustion CO_2 capture. Near-term applications of CO_2 capture from pre-combustion systems will likely involve physical or chemical absorption processes, with the current state-of-the-art being a physical glycol-based solvent called Selexol. Mid-term to long-term opportunities to reduce capture costs through improved performance could come from membranes and sorbents currently at the laboratory stage of development. Analysis conducted at NETL shows that CO_2 capture and compression using Selexol raises the cost of electricity from a newly built IGCC power plant by 30 percent, from an average of 7.8 cents/kWh to 10.2 cents/kWh. Research being conducted by the DOE Gasification Research Program is expected to improve gasification technology such that its costs without capture will be comparable to electricity costs from pulverized coal without capture, potentially reducing further the cost of pre-combustion CO_2 capture in the future.

Oxygen combustion (oxy-combustion). The objective of pulverized coal oxygen-fired combustion is to combust coal in an enriched oxygen environment using pure oxygen diluted with recycled CO_2 or H_2O (Figure 11). Under these conditions, the primary products of combustion are CO_2 and H_2O, and the CO_2 can be captured by condensing the water in the exhaust stream. Oxy-combustion offers several additional benefits, as determined through large-scale laboratory testing and systems analysis:

- A 60-70 percent reduction in NO_x emissions compared to air-fired combustion, mainly due to flue gas recycle, but also from reduced thermal NO_x levels due to lower available nitrogen. Some nitrogen is still available from coal nitrogen and air infiltrations.

- Increased mercury removal. Boiler tests of oxy-fuel combustion using Powder River Basin (PRB) coal resulted in increased oxidation of mercury, facilitating downstream mercury removal in the electrostatic precipitator and flue gas desulfurization systems.

- Applicability to new and existing coal-fired power plants. The key process principles involved in oxy-combustion have been demonstrated commercially (including air separation and flue gas recycle).

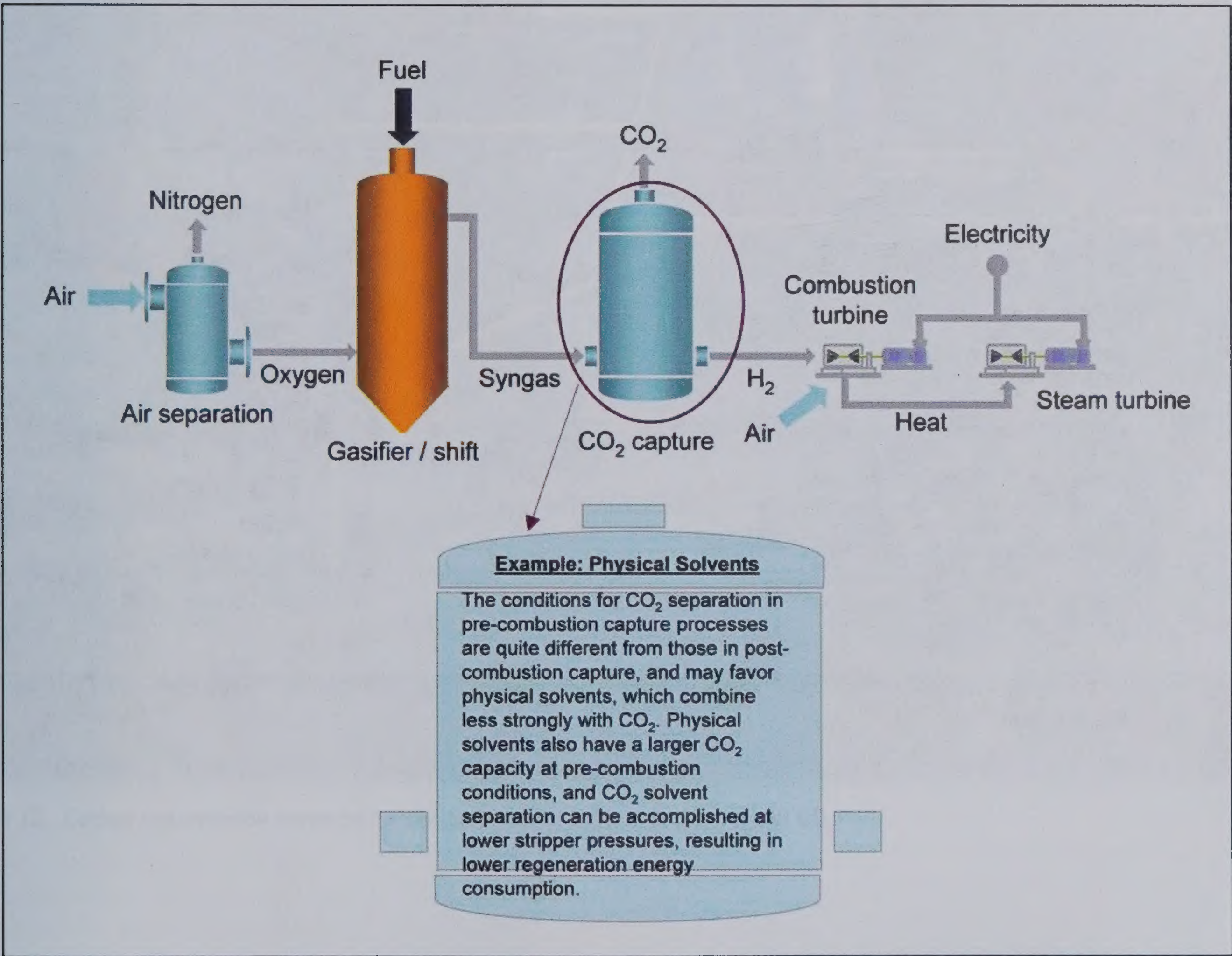


Figure 10. Pre-Combustion Capture

Both pre-combustion and oxy-combustion utilize air separation to combust coal in an enriched oxygen environment. However, it is important to note that the amount of oxygen required in oxy-combustion is significantly greater than in pre-combustion applications, increasing CO_2 capture costs. Oxygen is typically produced using low-temperature (cryogenic) air separation, but novel oxygen separation techniques such as ion transport membranes and chemical looping systems are being developed to reduce costs.

2. Carbon Storage

Carbon storage is defined as the placement of CO_2 into a repository in such a way that it will remain stored or sequestered permanently. It includes geologic sequestration and terrestrial sequestration. (Figure 12).

Geologic Sequestration. Geologic sequestration involves the injection of CO_2 into underground reservoirs that have the ability to securely contain it over long periods of time. The primary objective of Program research is to develop technologies to cost-effectively store and monitor CO_2 in geologic formations. Accomplishing this involves improved understanding of CO_2 flow and trapping within the reservoir and the development and deployment of technologies such as simulation models and monitoring systems. Experience gained from carbon sequestration field tests will facilitate the development of best practice manuals to ensure that sequestration does not impair the geologic integrity of underground reservoirs, thus assuring secured and environmentally acceptable CO_2 storage.

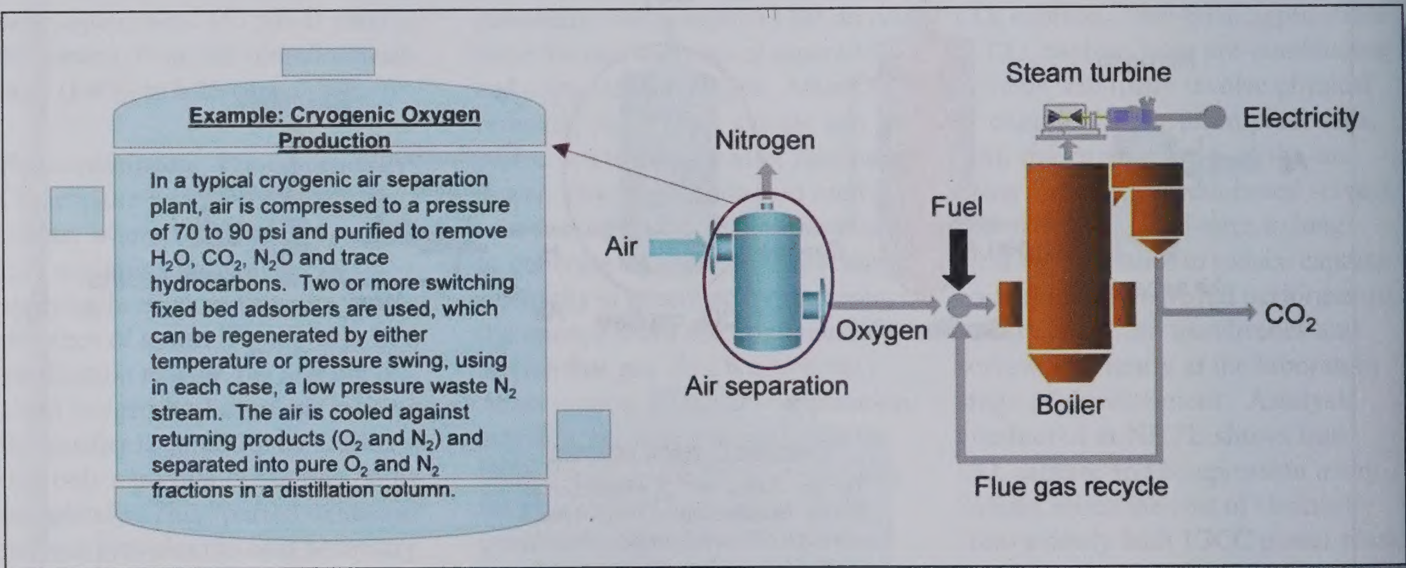


Figure 11. Oxy-Combustion

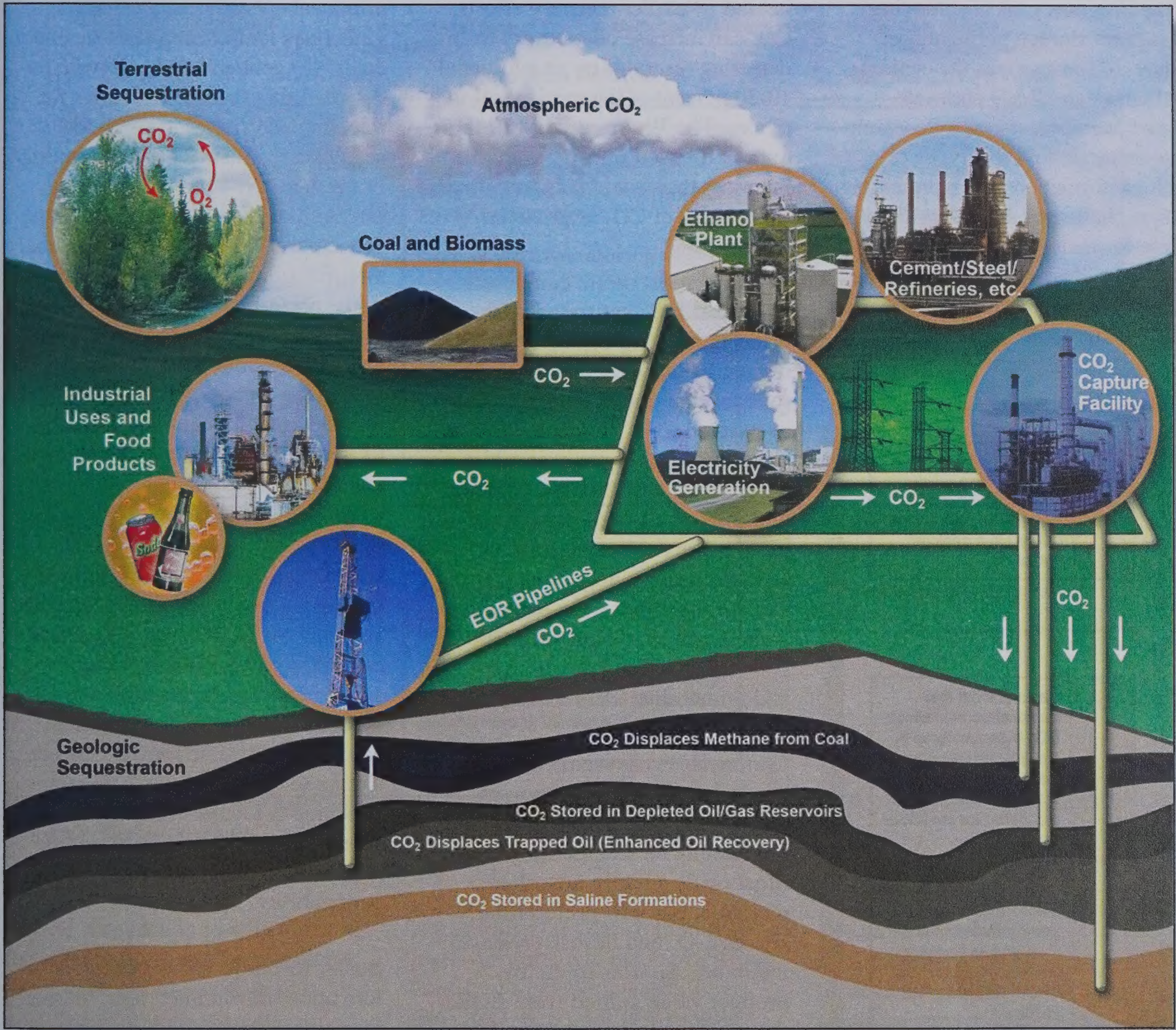


Figure 12. Carbon sequestration encompasses the processes of capture and storage of CO_2

Figure 13 highlights the Program R&D goals for the geologic storage research area. The goals are focused on reservoir characterization, storage potential, and large-scale injection, which are tied directly to the Program goal of achieving 99 percent storage permanence. Figure 14 summarizes the critical challenges and R&D pathways related to carbon storage. Research is concentrated on five types of geologic formations, each presenting unique challenges and opportunities. These formations include oil and gas reservoirs, deep saline formations, unmineable coal seams, oil and gas rich organic shales, and basalts.

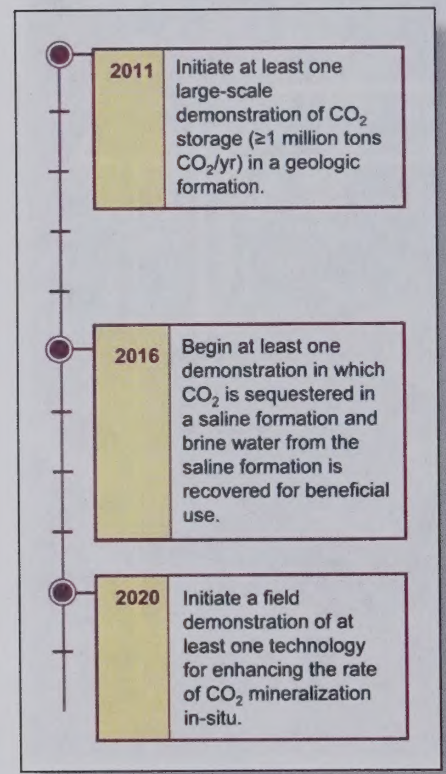


Figure 13. Geologic Storage Goals

Oil and gas reservoirs consist of porous rock strata that have trapped crude oil or natural gas for millions of years. An impermeable overlying rock formation forms a seal that traps the oil and gas; the same mechanism would apply to CO_2 storage. As a value-added benefit, CO_2 injected into these reservoirs can facilitate recovery of oil and gas resources left behind by earlier recovery efforts. CO_2 can increase oil recovery from a depleting reservoir by an additional 10-20 percent of the original oil in place. The Program work in this area is focused on CO_2 injection practices that would help maximize the amount of CO_2 sequestered.

Saline formations are composed of porous rock saturated with brine and capped by one or more regionally extensive impermeable rock formations enabling trapping of injected CO_2. Compared to coal seams or oil and gas reservoirs, saline formations are more common and offer the added benefits of greater proximity, higher CO_2 storage capacity, and fewer existing well penetrations. On the other hand, much less is known about the potential of saline formations to store and immobilize CO_2.

Unmineable coal seams, at depths beyond conventional recovery limits, represent another promising opportunity for CO_2 ECBM recovery. Most coals contain adsorbed methane, but will preferentially adsorb CO_2 and desorb (release) methane. Similar to the by-product value gained from EOR, the recovered methane provides a value-added revenue stream to the CCS process, creating a lower net cost option. While CO_2 injection is known to displace methane, a greater understanding of the displacement mechanism is needed to optimize CO_2 storage and to understand the problems of coal swelling and decreased permeability.

CO_2 storage in coal seams represents a promising sequestration pathway but research is needed along several fronts to overcome technical, economic, and environmental barriers: (i) storage capacity in deep, unmineable coal seams, including guidelines for defining unmineable coals; (ii) geologic and reservoir data defining favorable settings for injecting and storing CO_2 in coal seams; (iii) enhanced understanding of the near-term and longer-term interactions between CO_2 and coals, particularly the ability to model coal swelling (reduction of permeability) in the presence of CO_2; (iv) reliable, high-volume CO_2 injection strategies and well-spacing patterns that could reduce the number of wells required for storing significant volumes of CO_2; and (v) integrated CO_2 storage and ECBM recovery.

Shale, the most common type of sedimentary rock, is characterized by thin horizontal layers of rock with very low permeability in the vertical direction. Many shales contain 1-5 percent organic material and this hydrocarbon material provides an adsorption substrate for CO_2 storage, similar to CO_2 storage in coal seams. Research is focused on achieving economically viable CO_2 injection rates, given their generally low permeability.

Basalt formations are geologic formations of solidified lava. Basalt formations have a unique chemical makeup that could potentially convert all of the injected CO_2 to a solid mineral form, thus isolating it from the atmosphere permanently. Research is focused on enhancing and utilizing the mineralization reactions and increasing CO_2 flow within a basalt formation. Although oil and gas rich organic shales and

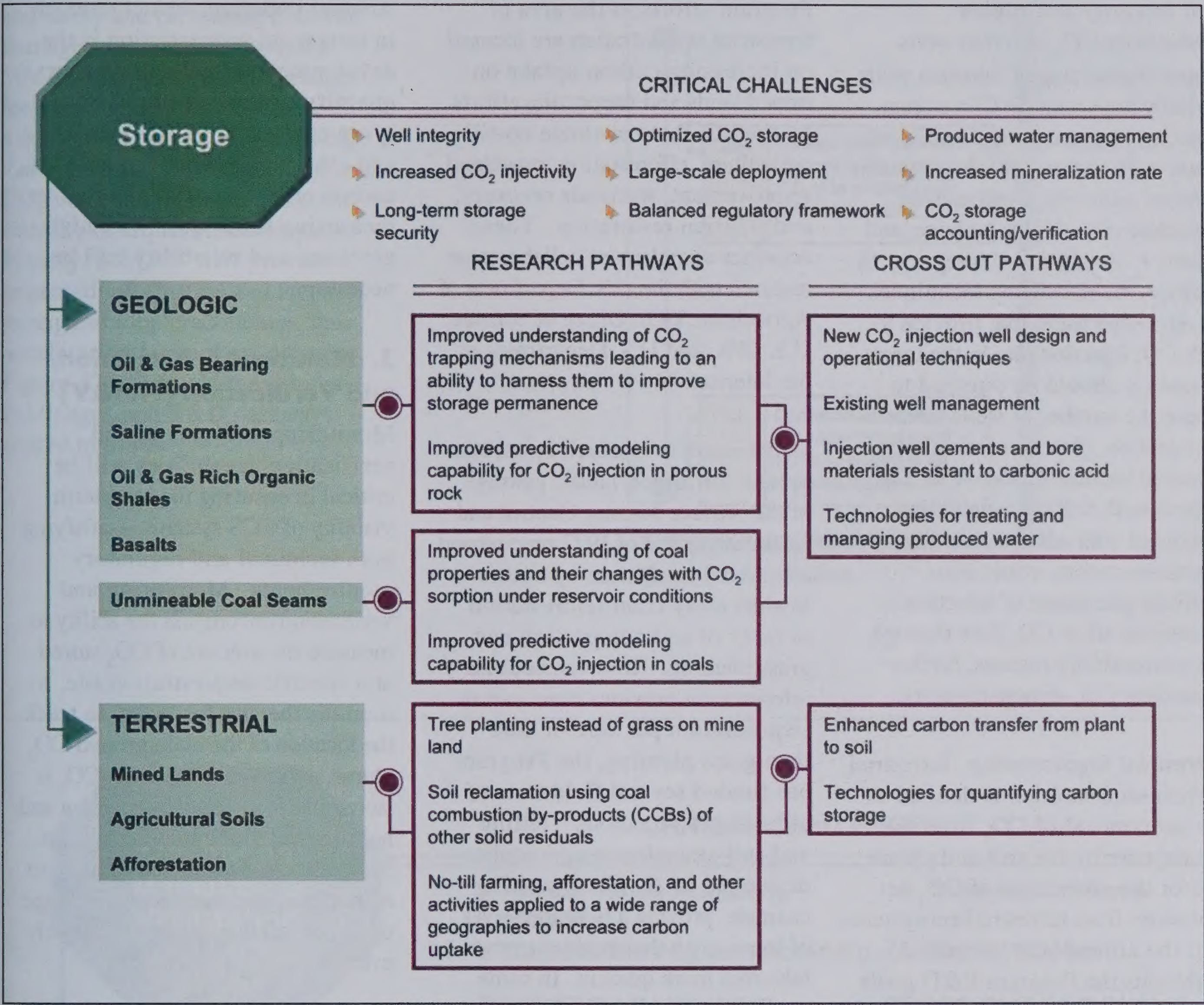


Figure 14. Storage Pathways

basalts research is in it's infancy, these formations may, in the future, prove to be optimal storage sites for stranded emissions sources.

Cross-cutting R&D Issues.
CO_2 trapping mechanisms within geologic reservoirs. Of emerging importance in the field of geologic sequestration is the science of maximizing the use of CO_2 trapping mechanisms. Like oil and natural gas, supercritical CO_2 is generally less dense than the reservoir water and exhibits a strong tendency to flow upward. Over time, CO_2 becomes less mobile as a combination of physical and geochemical trapping enhance the permanence of CO_2 stored within a geologic reservoir. Finally, coal and other organically-rich formations will preferentially adsorb CO_2 onto carbon surfaces as a function of reservoir pressure, thereby trapping CO_2.

Produced water. CO_2 injection for enhanced oil and gas recovery will result in salty water (brine) being displaced and produced at the surface. Produced water can be re-injected into deeper non-economic reservoirs, pooled in shallow ponds and evaporated, or treated and utilized for irrigation or other purposes. However, because produced water treatment is costly using current desalination and treatment technologies, alternative water treatment pathways are being explored.

Well integrity and higher productivity CO_2 injection wells. Proper engineering of injection wells is vitally important for CO_2 storage projects. Improving the integrity of future wells requires the development of novel cements, construction procedures to mitigate leakage, and sensors to monitor well integrity. In addition, novel drilling techniques for advanced wells that provide a high CO_2 injection rate in the target formation should be pursued to reduce the number of wells needed for injection, thereby minimizing potential leakage pathways for CO_2. Lateral well drilling capabilities, combined with advanced reservoir characterization, could also facilitate placement of injection points that allow CO_2 flow through low permeability regions, further expanding CO_2 storage capacity.

Terrestrial Sequestration. Terrestrial carbon sequestration is defined as the net removal of CO_2 from the atmosphere by the soil and plants and/or the prevention of CO_2 net emissions from terrestrial ecosystems into the atmosphere. Figure 15 highlights the Program R&D goals for the terrestrial sequestration focus area and Figure 14 describes the critical challenges and R&D pathways.

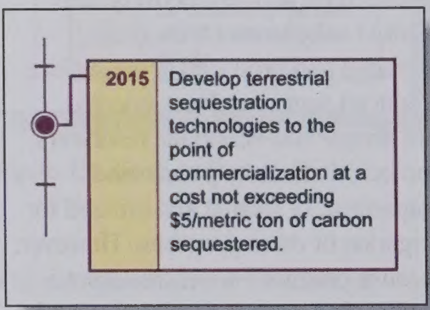


Figure 15. Terrestrial Storage Goal

Program efforts in the area of terrestrial sequestration are focused on increasing carbon uptake on mined lands and supporting efforts by the RCSPs to evaluate no-till agriculture, reforestation, rangeland improvement, wetlands recovery, and riparian restoration. These activities complement collaborative research with the U.S. Department of Agriculture, DOE Office of Science, U.S. EPA, and U.S. Department of the Interior.

With respect to research on carbon uptake for mined lands, passage of the Surface Mining Control and Reclamation Act of 1977 precipitated a move by coal mine operators to shift away from reforestation in favor of soil compaction and grass planting. However, because reforestation provides more carbon sequestration per acre of land than grass planting, the Program has funded several field tests of afforestation methods. Tilling and soil amendment approaches developed by the Program, for example, provide a 6-10 foot layer of loose earth that enables trees to take root more quickly. In some cases, the tilled land is amended with coal combustion by-products to reduce acidity. Field test results have been encouraging, demonstrating tree survival rates greater than 80 percent. These approaches can be applied to both closure practices at currently operating mines and reclamation of the nearly 1.5 million acres of land in the U.S. damaged by past mining practices. Initial concerns about erosion before saplings become established have not been realized because the deep layer of loose soil soaks up the water.

Another important area of research in terrestrial sequestration is the development of technologies for quantifying carbon stored in a given ecosystem. Should the U.S. and other nations one day adopt a carbon emissions trading program, measuring techniques with high precision and reliability will be necessary.

3. Monitoring, Mitigation, and Verification (MM&V)

Monitoring, mitigation, and verification capabilities will be critical in ensuring the long-term viability of CCS systems – satisfying both technical and regulatory requirements. Monitoring and verification encompass the ability to measure the amount of CO_2 stored at a specific sequestration site, to monitor the site for leaks, to track the location of the underground CO_2 plume, and to verify that the CO_2 is stored in a way that is permanent and not harmful to the host ecosystem. Mitigation is the near-term ability to respond to risks such as CO_2 leakage or ecological damage in the unlikely event that it should occur.

The MM&V goals shown in Figure 16 are focused on ensuring permanence, which support the overarching Program goal of achieving 90 percent carbon capture with 99 percent storage permanence. In general, MM&V research is aimed at providing an accurate accounting of stored CO_2 and a high level of confidence that the CO_2 will remain sequestered permanently. A successful effort will enable sequestration project developers to obtain permits for sequestration projects while ensuring human health

and safety and preventing potential damage to the host ecosystem. MM&V also seeks to set the stage for emissions reduction credits, if a domestic program is established, that approach 100 percent of injected CO_2, contributing to the economic viability of sequestration projects. Finally, MM&V will provide improved information and feedback to sequestration practitioners, thus accelerating technology progress. Figure 17 illustrates the critical challenges and R&D pathways related to MM&V.

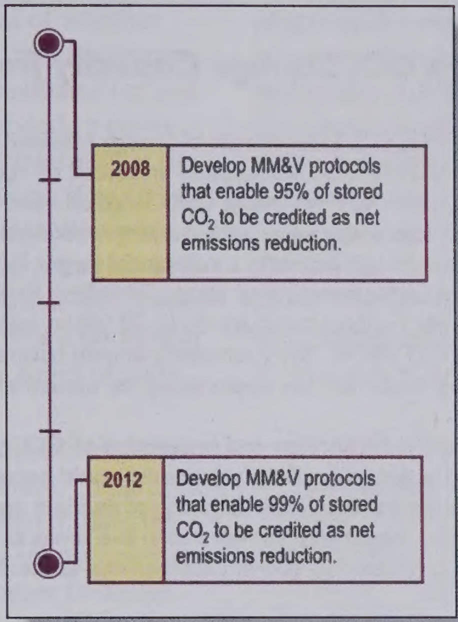


Figure 16. MM&V Goals

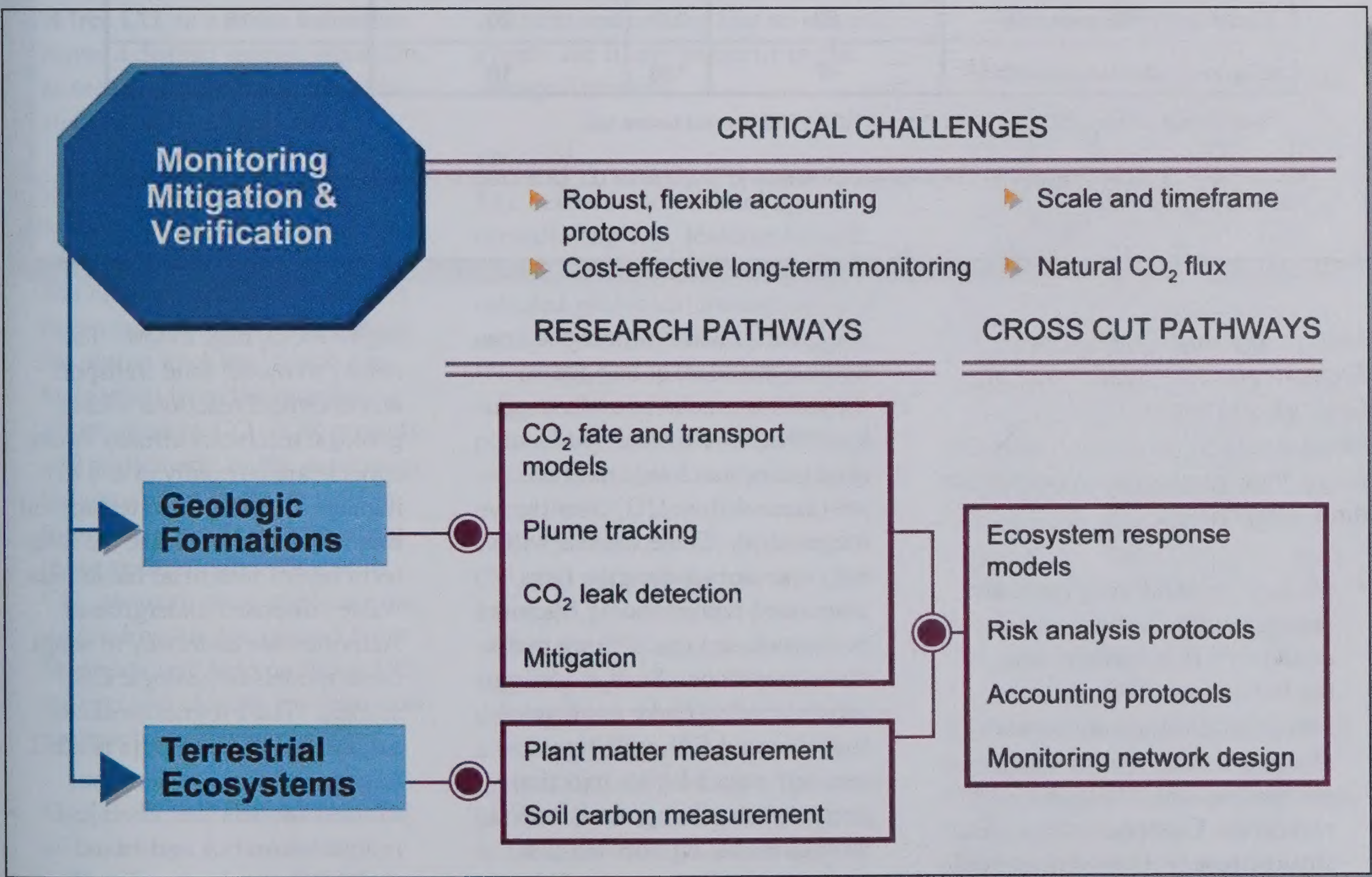


Figure 17. MM&V Pathways

Value-Added CO_2 Storage Capacity from Enhanced Oil Recovery

In February 2006, the U.S. Department of Energy released a series of ten basin studies that address CO_2 storage capacity from combining CO_2 storage and enhanced oil recovery (EOR). The studies cover 22 oil-producing states plus offshore Louisiana, encompassing 1,581 large oil reservoirs – accounting for two-thirds of U.S. oil production. Oil recovery practices today leave behind a large resource of "stranded oil" – 390 billion barrels in the regions studied. Such stranded oil provides a substantial target for EOR technology. As shown below, the ten regions have a technically recoverable potential of almost 89 billion barrels using the latest CO_2-EOR technologies. EOR applications in these regions could use up to 20 billion metric tons of CO_2. About 80 percent of this would become stored as part of CO_2-EOR. Since currently known natural CO_2 sources hold only about two billion metric tons, CO_2-EOR offers a major market opportunity for industrial CO_2.

With next-generation technology and integration of CO_2 storage and oil recovery, a much greater portion of the available CO_2 storage capacity in oil reservoirs could become useable. The advent of gravity-stable, vertical CO_2 injection with horizontal wells, the targeting of multiple zones and underlying saline formations, and continuous CO_2 injection (no water), could lead to more than five times as much CO_2 stored and nearly three times as much oil recovered when compared to current state-of-the-art technology.

These reports are available on the DOE web site at:
http://www.fe.doe.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html

	Recoverable Oil (billion barrels)	Purchased CO_2		Stored CO_2 (billion metric tons)
		(tcf)	(billion metric tons)	
Technically Recoverable	89	377	20	16
Economically Recoverable *	47	188	10	8

*$40 per bbl oil price, CO_2 cost of $0.80/Mcf, ROR of 15 percent before tax.

Source: "Basin Oriented Strategies for CO_2 Enhanced Oil Recovery," prepared for U.S. DOE Office of Fossil Energy by Advanced Resources International, April 2005.

Monitoring and Verification Technologies for CO_2 Storage in Geologic Formations.

Monitoring and verification activities for geologic sequestration encompass three components:

- *Modeling.* Modeling involves simulating the underground conditions that influence the behavior of CO_2 injected into geologic formations and characterizing any resulting geomechanical changes to the reservoir. Comprehensive CO_2 storage reservoir modeling will enable researchers to predict how CO_2 plumes will flow and become hydrodynamically trapped in the short term and to understand the effects of chemical reactions (and other mechanisms) that will immobilize CO_2 over the longer term. These models will help operators reduce the risks associated with inducing fractures in caprock and reactivating faults during injection. Such modeling capabilities engender confidence that injected CO_2 will remain securely stored *before* injection commences. Comprehensive CO_2 storage modeling does not just examine the target reservoir but also the potential pathways that fugitive CO_2 may follow. The ability to model fluid transport and chemical reactions within geologic reservoirs already exists. Models are currently in use to manage secondary and tertiary oil recovery and to examine the long-term fate of industrial hazardous wastes disposed underground. Activities are underway to adapt these models to geologic CO_2 storage. The Program seeks to acquire the detailed data needed to support reliable operation of these models (i.e., chemical reaction kinetics and two- and three-phase vapor/liquid equilibrium data at supercritical

conditions) and to develop integrated models that support early small-scale pilot field tests.

- *Plume tracking.* Underground plume tracking provides the ability to "map" the injected CO_2 and track its movement and fate through a reservoir. The ability to verify the location of injected CO_2 over time is necessary to assure storage permanence. Seismic surveys (e.g., 4-D seismic, time-lapse vertical seismic profiling) and sampling from wells (borehole logging) are key technologies used for plume tracking. Because supercritical CO_2 is less dense and more compressible than saline water, seismic waves travel through it at a different velocity. As a result of the velocity contrast, the presence of free CO_2 in a saline formation leaves a distinct seismic signature, as seen at the Weyburn (Canada) and Frio (Texas) field sites.

  Observation wells instrumented to monitor reservoir conditions such as pressure, temperature, and other properties are another important source of information for plume tracking. Much can be learned from the monitoring efforts used by CO_2 EOR projects and particularly by the gas storage industry. The Program work in this area is focused on adapting these technologies for use in CO_2 sequestration applications, where knowledge gained from field tests will help optimize CO_2 storage and identify the least-cost approach to effective MM&V.

- *Leak detection.* Beyond serving as backstops for modeling and plume tracking, CO_2 leak detection systems provide critical measures of whether CO_2 is escaping from the storage reservoir. One challenge for leak detection is the need to cover large areas cost-effectively at the required resolution. The CO_2 plume from an injection of one million tons of CO_2 per year in a deep saline formation for 20 years could be spread over a horizontal area of 15 square miles or more.

There are important interconnections among these three areas. Data from plume tracking enables validation of reservoir models; robust reservoir models enable operators to design and better interpret data from plume tracking; and models and plume tracking help focus leak detection efforts on high-risk areas. Such information provides a basis for addressing public and regulatory concerns and ensures that no adverse events are likely to occur in the storage formation.

Mitigation approaches.
The science and technology of remediating CO_2 leakage is still emerging. Storing CO_2 in rigorously selected geological formations such as at Weyburn (Canada), Sleipner (Norway), and In Salah (Algeria) suggest that the inherent risks and potential quantities of CO_2 leakage will be minimal. In the unlikely event that CO_2 leakage occurs, steps can be taken to arrest the flow of CO_2 and mitigate the impacts. For example, lowering the pressure within the CO_2 storage reservoir by stopping injection could reduce the driving force for CO_2 flow and close a leaking fault or fracture. Other options include forming a "pressure barrier" by increasing the pressure in the reservoir into which CO_2 is leaking or by intercepting the CO_2 leakage paths. Another strategy is plugging the region where leakage is occurring with low permeability materials. Additional research in this area is needed, especially on quantifying the costs associated with different remedial actions.

MM&V for Terrestrial Ecosystems.
MM&V activities focused on terrestrial ecosystems encompass three components:

- *Organic matter measurement.* Traditional methods for measuring carbon in terrestrial ecosystems (e.g., measuring tree diameters and analyzing soil samples in an off-site laboratory) are labor-intensive and costly. The Program is developing automated technologies that provide more detailed and timely information at lower cost for use in managing a sequestration site.

- *Soil carbon measurement.* Soil carbon offers the potential for long-term CO_2 storage. The Program is developing automated technologies for measuring soil carbon.

- *Modeling.* Detailed models are used to extrapolate the results of carbon uptake activities from random samples to an entire plot and to estimate the net increase in carbon storage relative to a case without enhanced carbon uptake. Economic models show accumulations of emissions credits and revenues versus an initial investment.

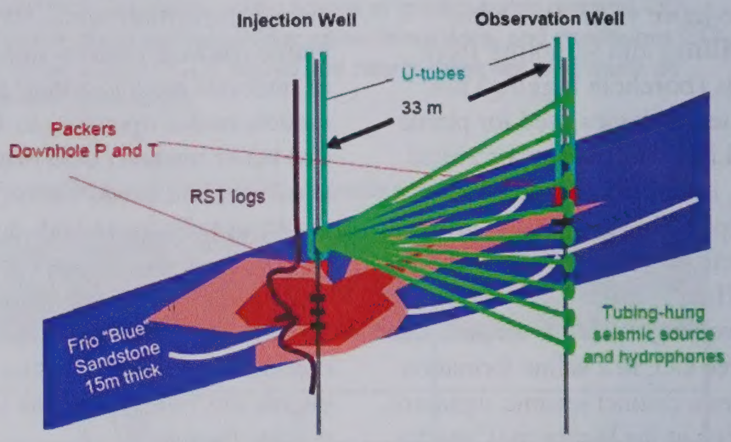
These three components have a vital role in proving the permanence of CO_2 storage in terrestrial ecosystems. Continued research is needed, particularly since quantifying CO_2 leakage rates from terrestrial ecosystems using current technology

Frio MM&V Technology a Star Performer

The Frio 2 test represents a major step forward in the DOE Carbon Sequestration Program. Initiated on September 25, 2006, the project injected about 700 tons of CO_2 a mile underground to determine the feasibility of geologic CO_2 storage in brine formations. By closely monitoring the CO_2 flow with technologically advanced instruments over 12 months, researchers will assess whether these formations can effectively store CO_2 over long periods of time.

The current test follows an October 2004 pilot that provided the first demonstration of subsurface CO_2 injection and monitoring in the United States. The Frio 2 test uses several different techniques to provide information about CO_2 flow, trapping, and dissolution: wireline logging, cross well seismic, downhole pressure and temperature monitoring, and a tracer program. One of the new tools tested, a tubing-conveyed source and receiver string (U-tube), developed by Lawrence Berkeley National Laboratory (LBNL) is designed to fully integrate seismic measurements with other downhole data, including downhole pressure, temperature, geochemistry, and wireline saturation logs.

In this application of seismic tomography, the seismic source is fixed downhole, above the packer. Since the seismic source is fixed, error from the placement and replacement of equipment using traditional means is minimized. In addition, real-time data is collected every 10 seconds, allowing researchers to know exactly when CO_2 breaks a given ray-path between the source and receiver as it rises in the reservoir. This technique offers an exciting opportunity for mature applications in large-scale injection.



Monitoring plan for Frio 2 injection

is more challenging than identifying leaks in geologic storage formations. In addition, the development of robust and flexible accounting protocols that function within future regulatory and market regimes is critical to the verification of long-term storage in terrestrial ecosystems.

Accounting protocols. Monitoring and measurement systems must provide certainty to project owners, regulators and the global environmental community that sequestration projects are achieving and sustaining expected levels of CO_2 permanence. A key challenge facing the carbon sequestration community, therefore, is the development of robust, equitable, and transparent accounting mechanisms with the flexibility to function within future regulatory and market regimes.

4. Non-CO_2 Greenhouse Gas Control

According to the EIA, non-CO_2 greenhouse gas emissions contributed 16 percent of the total U.S. GHG emissions in 2005. Since many non-CO_2 greenhouse gases (e.g., methane, nitrous oxide, and certain refrigerants) have significant economic value, emissions can often be captured or avoided at low net cost. The Carbon Sequestration Program aims to tap the economic value of fugitive methane emissions by developing innovative capture and gas upgrading technologies.

Two large sources of methane and GHGs in the U.S. – landfills and coal mines – represent priority R&D pathways for the Carbon Sequestration Program (Figure 18). In one pathway, the produced methane is combusted, reducing the carbon's GHG effect by a factor of ten. In the other pathway, the produced methane is captured and utilized.

Landfill gas is typically a 50/50 mixture of methane and CO_2, with trace amounts of heavier hydrocarbons. The Program is exploring methods to enhance the biological utilization of methane in landfill covers and studying management practices at bioreactor landfills to control the conditions

within the landfill to promote or suppress methane production. The Program is also exploring techniques to enhance methane capture and use for energy generation, including the injection of landfill gas into unmineable coal seams to harness the natural ability of coal to adsorb CO_2, thus replacing and releasing methane for ECBM.

Methane emissions from coal mines represent about 10 percent of U.S. anthropogenic methane emissions. Ventilation air methane (VAM) is the largest source of coal mine methane – accounting for about half of the methane emitted from U.S. coal mines. The Program is pursuing technologies to cost-effectively convert the methane in coal mine ventilation air to CO_2. Methane can also be recovered from mine degasification systems, where methane concentrations are much higher (30-90 percent) than in coal mine VAM (0.3-1.5 percent). Here, the Program aims to develop and deploy cost-effective technologies to upgrade gas to pipeline quality specifications. The Program is collaborating with the U.S. EPA, which has both coal mine methane and landfill gas outreach programs.

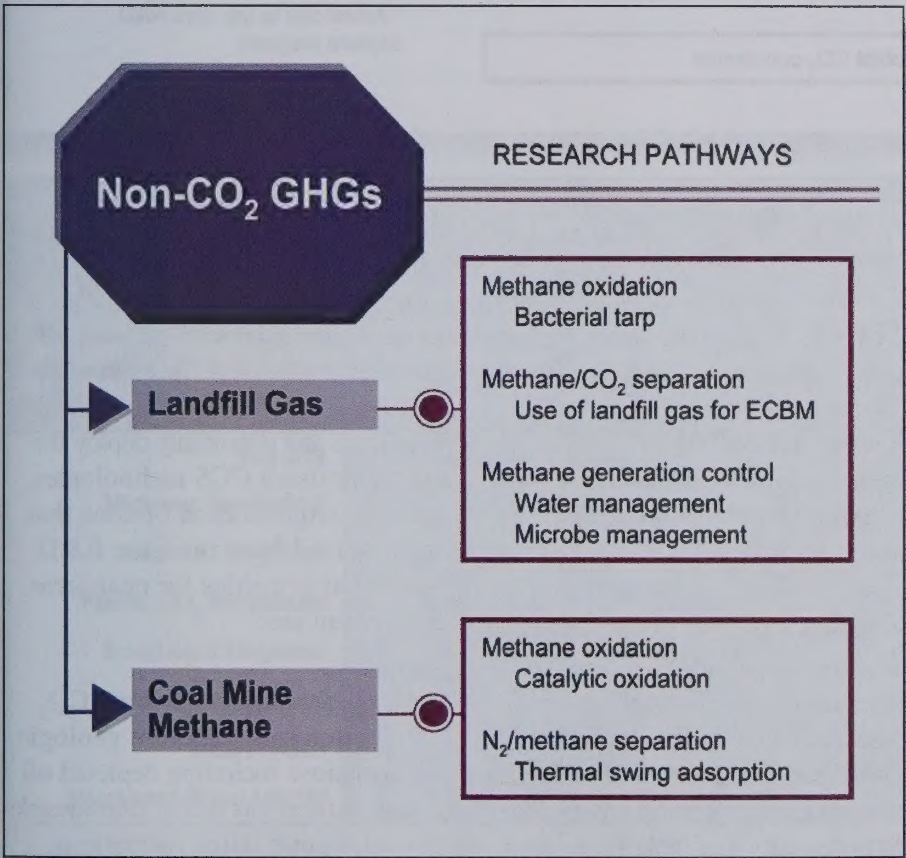


Figure 18. Non-CO_2 GHG Pathways

5. Breakthrough Concepts

DOE is committed to fostering the innovative potential of industry and academia. The Breakthrough Concepts focus area serves as an incubator for CO_2 capture, storage, and conversion concepts with the potential to provide step-change improvements in process efficiency, energy use, and cost. Figure 19 illustrates some of the research pathways being pursued in the Breakthrough Concepts focus area.

In October 2006, DOE announced the selection of nine projects aimed at developing novel and cost-effective technologies for CO_2 capture from coal-fired power plants. Two of these projects have matured from Breakthrough Concepts selections under a 2004 joint DOE/National Academies of Science (NAS) solicitation to the Core R&D CO_2 Capture focus area, where they will be advanced to the pre-pilot scale. One project will focus on the development of a new class of liquid absorbents called ionic liquids for efficient post-combustion capture of CO_2 from coal-fired power plants. The other project will develop a process that uses novel microporous metal organic frameworks having extremely high adsorption capacities for the removal of CO_2 from coal-fired power plant flue gas. The Program also supports research in membranes and mineralization, including a project to create microbes that biologically sequester CO_2 by converting it to other value-added chemicals that have use in certain drug compounds, agricultural and food production, and biodegradable plastics.

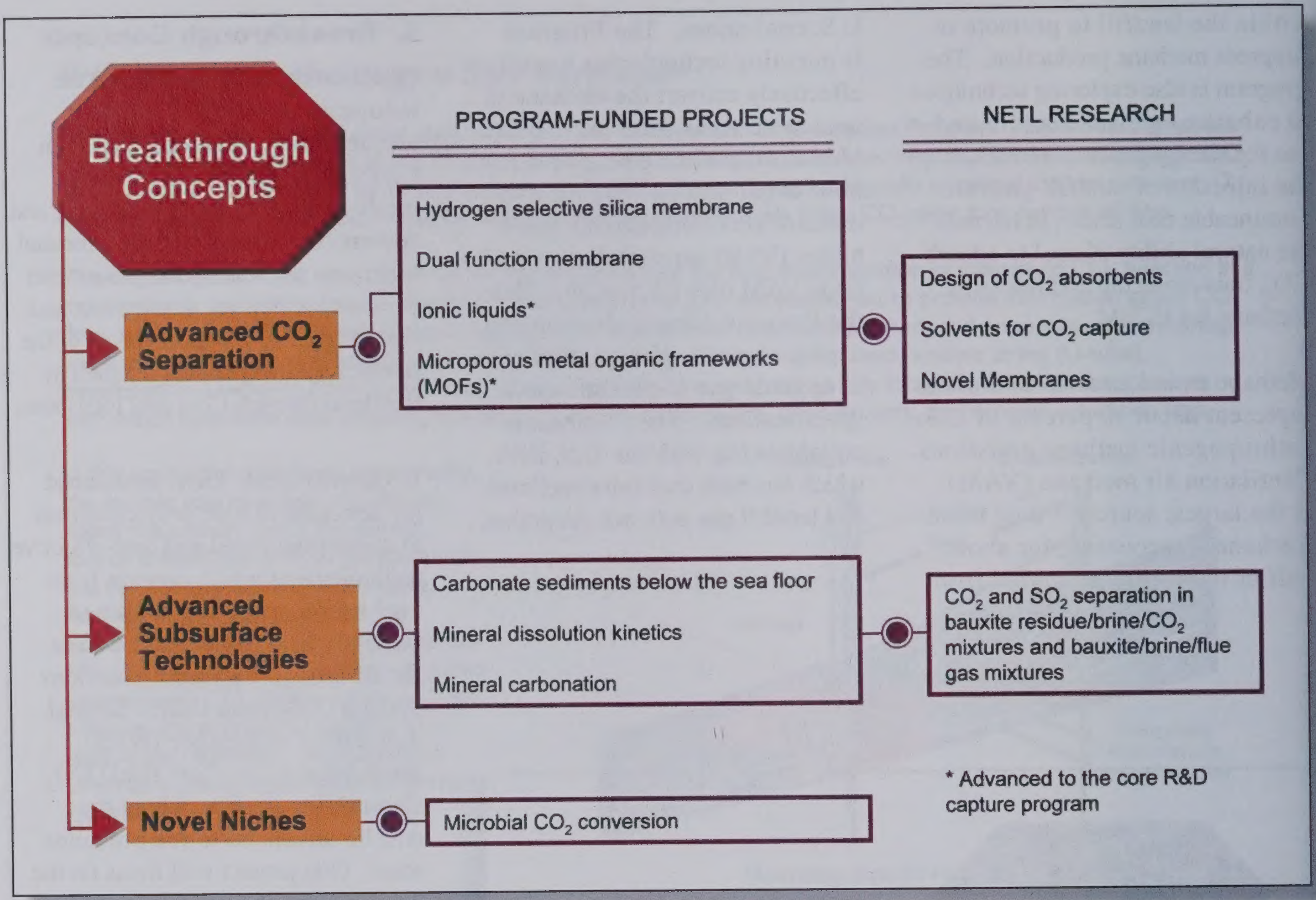


Figure 19. Breakthrough Concepts

B. Regional Carbon Sequestration Partnerships

1. Overview

Geographic differences in fossil fuel use and potential sequestration storage sites across the U.S. dictate the use of regional approaches in addressing CO_2 sequestration. DOE has created a network of seven Regional Carbon Sequestration Partnerships to develop the technology, infrastructure, and regulations necessary to implement CO_2 sequestration in different regions of the Nation. Underlying this regional partnership approach is the belief that local entities, organizations, and citizens will contribute expertise, experience, and perspectives that more accurately represent the concerns and desires of a given region, resulting in the development and application of technologies better suited to that region.

Collectively, the seven RCSPs represent regions encompassing 97 percent of coal-fired CO_2 emissions, 97 percent of industrial CO_2 emissions, 96 percent of the total land mass, and essentially all the geologic sequestration sites in the U.S. potentially available for carbon storage. The RCSPs are evaluating numerous sequestration approaches to assess which approaches are best suited for specific regions of the country and are developing the framework needed to validate and potentially deploy the most promising CCS technologies. The two sequestration options that have evolved from the Core R&D element as priorities for near-term deployment are:

- Geologic Sequestration – CO_2 injection into different geologic formations including depleted oil and natural gas fields, unmineable coal seams, saline formations, shale, and basalt outcrops

- Terrestrial Sequestration – carbon sequestration in soils and organic material through the restoration of agricultural fields, grasslands, rangeland, wetlands, and forests or by altering the management of these assets

Among the seven RCSP Regions, geologic sequestration sites differ in their lithology as well as their locations relative to CO_2 emission sources and pipelines. Some regions have an abundance of different types of geologic formations, while opportunities in other regions are dominated by a specific formation type. Terrestrial sequestration options vary across regions based on differences in average temperature, topography, soil type, amount of rainfall, and other factors.

The process of sequestering carbon dioxide involves identifying sources that produce CO_2 and identifying sequestration sites where the CO_2 can be stored. Based on data assembled for the *Carbon Sequestration Atlas of the United States and Canada*, Table 1 shows that 4,365 identified stationary sources in the seven RCSP Regions and the northeastern U.S. generate about 3.809 billion metric tons of CO_2 annually. The aggregate CO_2 sink capacity – including saline formations, unmineable coal seams, and oil and natural gas reservoirs – is estimated to range up to 3,643 billion metric tons, enough to sequester CO_2 emissions at current annual generation rates for hundreds of years. The formation maps in Figure 20 show the geographic locations of these CO_2 sources and potential geologic sequestration sites.

The RCSPs include more than 350 organizations and span 41 states, three Indian nations, and four Canadian provinces. The partners include utilities, oil and natural gas companies, ethanol producers, agricultural industry, other industrial partners, state and local government organizations, regional universities, national laboratories, and special interest groups representing industrial and environmental communities. Table 2 provides website, acronym, lead organization, and geographic coverage information for the RCSPs.

Table 1. Capacity Estimates of CO_2 Sources and Geologic Sequestration Sites

Regional Partnership or Geographic Region	CO_2 Sources		Geologic Sequestration Site Capacities (billion metric tons of CO_2)				
	Quantity (billion metric tons of CO_2)	Number of Facilities	Deep Saline Formations		Oil and Gas Reservoirs	Unminable Coal Seams	
			Low	High		Low	High
Big Sky	0.112	158	271	1,085	0.8	0.0	0.0
Midwest Geological	0.343	212	29	115	0.4	2.3	3.3
Midwest Regional	1.319	496	47	189	2.5	0.7	1.0
Plains CO_2 Reduction	0.401	1,037	97	97	19.6	8.0	8.0
Southeast Regional	1.021	981	360	1,440	32.4	57.4	82.1
Southwest Regional	0.336	432	18	64	21.4	0.9	2.3
WESTCARB	0.132	62	97	388	5.3	86.8	86.8
Northeast (from USGS)	0.144	987	—	—	—	—	—
Total	3.809	4,365	919	3,378	82.4	156.1	183.5

Source: "Carbon Sequestration Atlas of the United States and Canada," DOE/Office of Fossil Energy/NETL, April 2007.

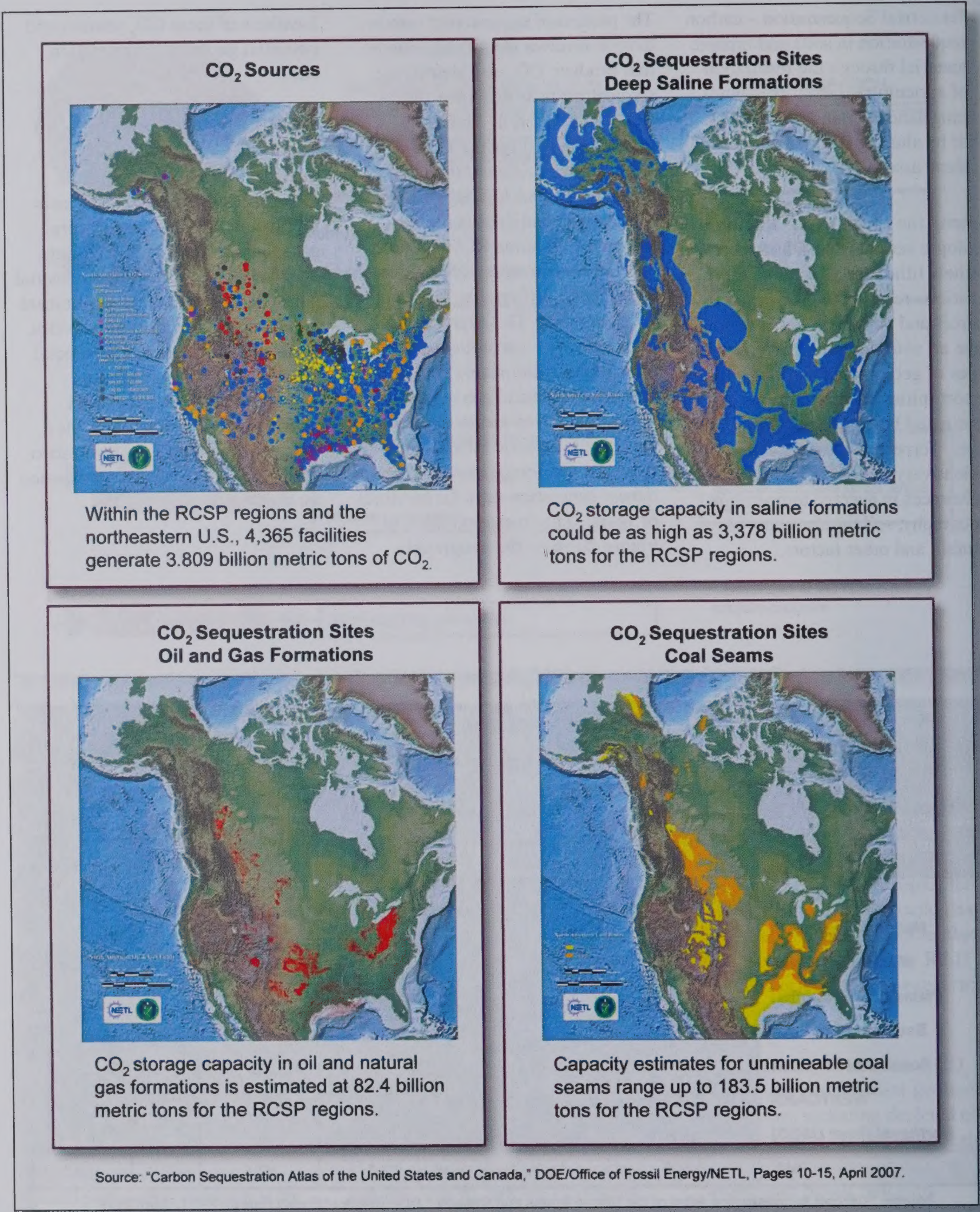


Figure 20. Maps for CO_2 Sources and Geologic Sequestration Sites

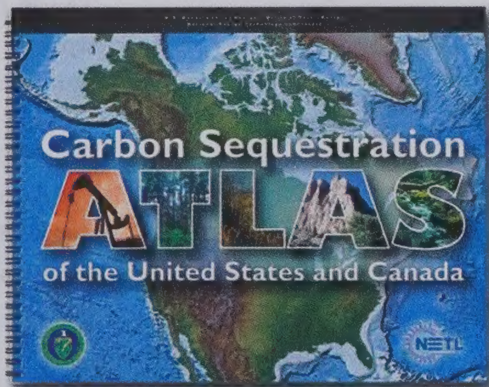
Table 2. Regional Partnerships

Regional Partnership/ Website Address	Acronym/ Abbreviated Name	Lead Organization	States/Provinces Covered
Big Sky Carbon Sequestration Partnership http://www.bigskyco2.org/	Big Sky	Montana State University	ID and portions of MT, SD, WY, WA, OR
Midwest Geological Sequestration Consortium http://www.sequestration.org/	MGSC	University of Illinois, Illinois State Geological Survey	IL and portions of IN, KY
Midwest Regional Carbon Sequestration Partnership http://198.87.0.58/	MRCSP	Battelle Memorial Institute	MD, MI, NY, OH, PA, WV and portions of IN, KY
Plains CO_2 Reduction Partnership http://www.undeerc.org/pcor/	PCOR	University of North Dakota, Energy & Environmental Research Center	IA, MN, MO, NE, ND, WI, Alberta, Manitoba, Saskatchewan and portions of MT, SD, WY
Southeast Regional Carbon Sequestration Partnership http://www.secarbon.org/	SECARB	Southern States Energy Board	AL, AR, FL, GA, LA, MS, NC, SC, TN, VA and portions of KY, TX
Southwest Regional Partnership on Carbon Sequestration http://www.southwestcarbonpartnership.org/	SWP	New Mexico Institute of Mining and Technology	CO, KS, OK, NM, UT and portions of AZ, TX, WY
West Coast Regional Carbon Sequestration Partnership http://www.westcarb.org/	WESTCARB	California Energy Commission	AK, CA, NV, British Columbia and portions of AZ, OR, WA

Carbon Sequestration Atlas of the United States and Canada

DOE and the seven Regional Carbon Sequestration Partnerships gathered and compiled information on CO_2 emission stationary sources, geologic formations with sequestration potential, and terrestrial ecosystems with potential for enhanced carbon uptake – all referenced to their geographic location – to enable matching sources and sequestration sites. This data formed the basis for the *Carbon Sequestration Atlas of the United States and Canada*, which estimates the amount of CO_2 that can be stored in subsurface geologic environments on a formation-by-formation or basin-by-basin basis. While this *Atlas* is not intended as a substitute for site-specific assessment and testing, it does provide a valuable preliminary assessment of sources and storage sites for CO_2 sequestration projects.

The methodologies used to calculate these capacity estimates were designed to integrate the results for the seven RCSPs for three types of geologic formations: saline formations, unmineable coal seams, and hydrocarbon (oil and natural gas) reservoirs. These methodologies are consistent across North America for a wide range of data. Access to much of the data in the *Atlas* is available through the National Carbon Sequestration Database and Geographic Information System (NATCARB, www.natcarb.org). NATCARB is an interactive relational database management system with spatial query capabilities to evaluate the geographic distribution, physical characteristics, and economic parameters of potential CO_2 sources and geologic sequestration sites. The *Atlas* can be downloaded at: http://www.netl.doe.gov/publications/carbon_seq/atlas/index.html.



Each of the RCSPs is described below in terms of participating organizations, strategic focus on field testing, and types of CO_2 storage opportunities being evaluated.

BIGSKYCARBON
SEQUESTRATION PARTNERSHIP

The **Big Sky Carbon Sequestration Partnership (Big Sky)** is comprised of 66 partners and native American tribes. The Big Sky Partnership has extensive basalt formations, saline formations, and oil and natural gas reservoirs that could be used as storage sites. Geologic field tests are planned in deep saline and depleted oil fields. The Big Sky Partnership is also exploring the Region's potential to store CO_2 in agricultural soils, rangeland soils, and forests. Three terrestrial tests are planned to examine CO_2 uptake.

MGSC

The **Midwest Geological Sequestration Consortium (MGSC)** is comprised of 21 partners and is assessing the ability of geological formations in the Illinois Basin to store CO_2 in unmineable coal seams, mature oil fields, and deep saline formations. Highly favorable storage areas may exist in this Region since two or more potential CO_2 sink types are vertically stacked in some localities. MGSC will also investigate CO_2 capture technologies and the costs of transporting large quantities of CO_2 via pipeline. Six small pilot projects will evaluate EOR by CO_2 flooding, CO_2 sequestration in unmineable coal seams, and CO_2 injection into deep saline formations up to 10,000 feet below the Earth's surface.

MRCSP
MIDWEST REGIONAL
CARBON SEQUESTRATION
PARTNERSHIP

The **Midwest Regional Carbon Sequestration Partnership (MRCSP)** has 36 partners and is determining the CO_2 storage potential of various geologic formations, particularly saline formations. MRCSP will conduct three CO_2 injection field tests in deep geologic formations in the Region to demonstrate the safety and effectiveness of geologic sequestration systems. MRCSP will also conduct three terrestrial sequestration field tests to explore how naturally stored carbon can be measured and monitored and how carbon credits could be traded in voluntary GHG markets.

The Plains CO_2 Reduction Partnership
PCOR Partnership

The **Plains CO_2 Reduction Partnership (PCOR)** consists of 63 partners working to demonstrate the potential of depleted oil fields, and unmineable lignite coals to store CO_2 emissions. Geologic tests are planned in the oil-bearing Keg River and Duperow formations in Alberta province and North Dakota, respectively, while a coal seam sequestration test is planned for the Williston Basin in North Dakota. The Partnership also plans to demonstrate that carbon can be stored in the native grasslands and through the restoration of wetlands. Terrestrial field tests are planned for the Great Plains Prairie Pothole wetlands complex.

The **Southeast Regional Carbon Sequestration Partnership (SECARB)** has 77 partners working to characterize carbon sources and potential sequestration sites in the Southeast; identify the most promising capture, sequestration, and transport options; and address issues for technology deployment. SECARB will conduct four geologic sequestration field tests covering EOR stacked formations along the Gulf Coast, coal seam sequestration and coalbed methane recovery, and saline formations.

Southeast Regional Carbon Sequestration Partnership

The **Southwest Regional Partnership on Carbon Sequestration (SWP)** has 52 partners in eight states, including the Navajo nation. SWP is investigating a variety of carbon sink targets. The Partnership will leverage 30 years of EOR experience in the Region to determine the potential of oil, coal, and saline formations to store CO_2 emissions. Field testing of ECBM production with carbon sequestration is planned. The Partnership is also investigating the potential of terrestrial systems in the Southwest to store CO_2, including a riparian restoration project using produced water from the ECBM field test.

SWP
SOUTHWEST PARTNERSHIP
CO_2 SEQUESTRATION

The **West Coast Regional Carbon Sequestration Partnership (WESTCARB)** is comprised of 78 partners dedicated to evaluating regional CCS opportunities. The Partnership is examining the sequestration potential in depleted oil, unmineable coal, and deep saline formations. One EOR and saline storage test is planned in California and one saline storage test in Arizona. Terrestrial sequestration pilot projects will be conducted in Oregon and California. The Partnership will also investigate the use of reforestation and fire suppression to mitigate CO_2 emissions.

West Coast Regional Carbon Sequestration Partnership
westcarb.org

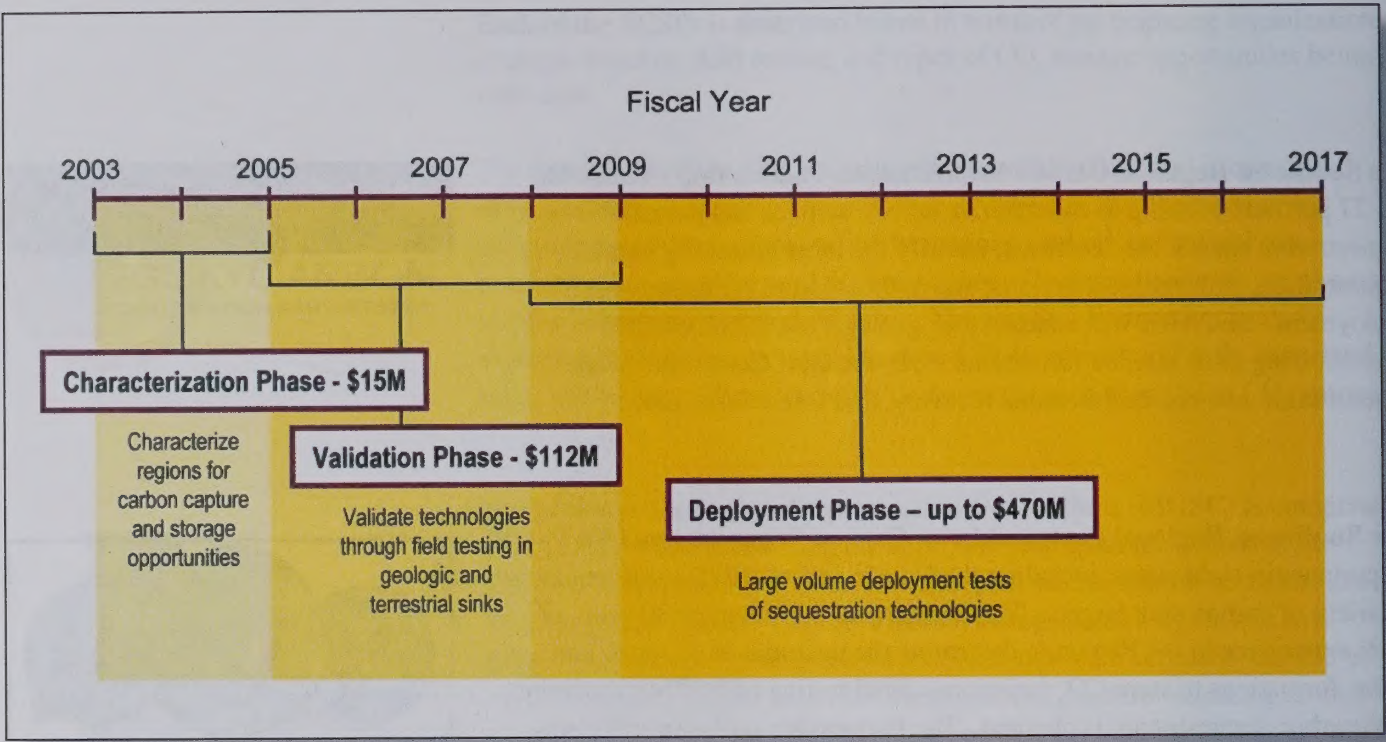


Figure 21. Regional Partnership Phases

2. RCSP Program

The RCSP Program was initiated in September 2003 through an open competitive solicitation process that required a minimum 20 percent cost share from the prospective awardees. As Figure 21 illustrates, the RCSP Program is being implemented in three interrelated phases. Levels of DOE funding without cost shares are shown.

- Characterization Phase (FY 2003 – FY 2005)
- Validation Phase (FY 2005 – FY 2009)
- Deployment Phase (FY 2008 – FY 2017)

Actual cost shares for the RCSPs through the Characterization and Validation Phases have ranged from the 20 percent minimum to as high as 52 percent. As a group, the seven RCSPs have provided more than 31 percent in cost sharing through the first two phases.

Even though the RCSP Program is being implemented in three phases, it should be viewed as an integrated whole, with many of the goals and objectives transitioning from one phase to the next. Accomplishments and results from the Characterization Phase have helped to refine goals and activities in the Validation Phase, and results from the Validation Phase are expected to flow into and enhance the Deployment Phase.

The RCSP Program encourages and requires open information sharing among its members. DOE and the RCSPs sponsor both general workshops and more focused technology area Working Group meetings to facilitate information exchange. These meetings are important tools that strengthen the overall RCSP Program. Although each RCSP has its own objectives and field tests, mutual cooperation has been an important part of the Program to date. These workshops and formal Working Group activities were initiated during the Characterization Phase, have continued into the Validation Phase, and will likely be an important aspect of the Deployment Phase as well.

3. Characterization Phase

The Characterization Phase, completed in 2005, focused on characterizing regional opportunities for carbon capture and storage, identifying regional CO_2 sources, and identifying priority opportunities for field tests. Each RCSP developed decision support systems that house regional geologic data on CO_2

storage sites and information on CO_2 sources to complete source-sink matching models. Each RCSP also researched project tools necessary to model and measure the fate and spread of CO_2 after injection. Combined with public outreach and education programs conducted by the RCSPs during the Characterization Phase, these activities show that CCS is a viable option to mitigate CO_2 emissions. In preparation of the Validation and Deployment Phases, the RCSPs gathered data necessary to prepare and conduct geologic and terrestrial field tests, and made the following key accomplishments:

- *Established a national network of companies and professionals working to support sequestration deployments.* The RCSPs brought an enormous amount of capability and experience together to work on the challenge of infrastructure development. Together with DOE, the RCSPs secured the active participation of more than 500 individuals representing more than 350 industrial companies, engineering firms, state agencies, non-governmental organizations, and other supporting organizations.

- *Raised awareness and support for CCS as a GHG mitigation option.* Each RCSP developed creative and innovative approaches to outreach and education. Articles about sequestration have been placed in local newspapers, documentaries have been shown on public television, and several people involved in the RCSPs made appearances on local television programs. All seven RCSPs developed websites that describe their activities and several RCSPs experimented with innovative, internet-based outreach efforts, including a modified chat room for fielding questions about sequestration and town hall style meetings.

- *Advanced understanding of permitting requirements for future CCS projects.* To comply with public and regulatory requirements and to address possible safety and environmental risks, CCS projects will require permits. Working in collaboration with the Interstate Oil and Gas Compact Commission (IOGCC) and in consultation with the U.S. EPA, the RCSPs assessed requirements and procedures for permitting future commercial sequestration deployments.

Regional Carbon Sequestration Partnership Working Groups – A Key Element of Program Success

Early in the Regional Carbon Sequestration Partnership (RCSP) Program, the members recognized that, despite their regional differences, they faced many common challenges. To provide a forum for sharing information and to develop uniform approaches for dealing with these common challenges, the RCSPs established various *Working Groups*. Six Working Groups were formed in October 2003: Geologic Characterization and Infrastructure Requirements, Capture and Transportation, Public Education and Outreach, Regulatory, Terrestrial Sequestration, and Geographic Information System (GIS)/Database. These Working Groups, coupled with a limited access website, enable the RCSPs to maintain open lines of communication and to coordinate efforts and activities.

Although the Working Groups were initiated during the Characterization Phase, information sharing significantly increased during the Validation Phase as each of the RCSPs became more established and began field validation activities. Further, the need to develop a uniform approach to a variety of common issues became more apparent, along with the sense that an organized, national perspective on characterization, validation, and deployment issues for the Carbon Sequestration Program would be valuable.

These Working Groups remain active in 2007 and are key to the successful progress of the RCSPs. These Working Groups are composed of one or more representatives from each of the seven RCSPs and are each led by a coordinator. A Working Group focused on MM&V has recently been formed.

- *Identified priority opportunities for sequestration field tests.* The RCSPs identified high priority opportunities within their Regions that target select field tests during the Validation Phase.

- *Established a series of protocols for project implementation, accounting, and contracts.* RCSP activities in this area focused on the development of accounting protocols and support for state or national GHG accounting registries.

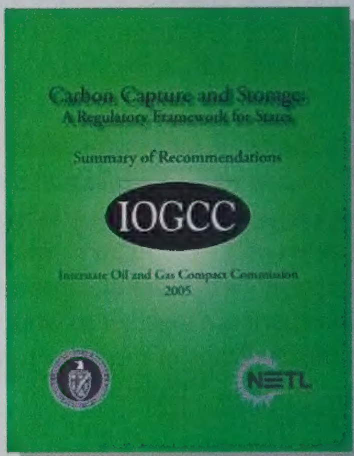
4. Validation Phase

The Validation Phase focuses on field tests to validate the efficacy of CCS technologies in a variety of geologic and terrestrial storage sites throughout the U.S. and Canada. Using the extensive data and information gathered during the Characterization Phase, the seven RCSPs identified the most promising opportunities for carbon sequestration in their Regions and are performing 25 geologic field tests (Figure 22) and 11 terrestrial field tests (Figure 23). In addition, the RCSPs are verifying regional CO_2 sequestration capacities, satisfying project permitting requirements, and conducting public outreach and education activities.

The first four geologic projects listed in Figure 22 are large-scale injections where a commercial partner is already injecting CO_2 into depleted oil reservoirs and unmineable coal seams for EOR and/or ECBM recovery applications. The partner is focusing its efforts to determine the fate of the injected CO_2 through predictive modeling and monitoring activities. The remaining projects will involve injection of a relatively small amount of CO_2 into unmineable coal seams, oil and natural gas reservoirs, and saline formations to assess the sequestration potential of these geologic sites. The RCSPs are working to develop injection and monitoring wells, coordinate injection operations, conduct reservoir modeling, and monitor the fate of the CO_2. In addition, the RCSPs are conducting public outreach activities and satisfying the necessary permit applications. To successfully conduct these geologic field tests, the RCSPs are collaborating with industrial partners that are providing the financial and technical support necessary for the success of the program.

Interstate Oil and Gas Compact Commission (IOGCC) Report

The RCSPs participated on a Geological CO_2 Sequestration Task Force formed by the Interstate Oil and Gas Compact Commission (IOGCC) to examine the technical, policy, and regulatory issues related to safe and effective storage of CO_2 in depleted oil and natural gas fields, saline formations, and unmineable coal beds. Comprised of representatives from IOGCC member states and international affiliate provinces, state oil and natural gas agencies, the RCSPs, the Association of American State Geologists (AASG), and other interested parties, the Task Force divided the carbon capture and geological storage process into four key areas, offering the following conclusions/recommendations:

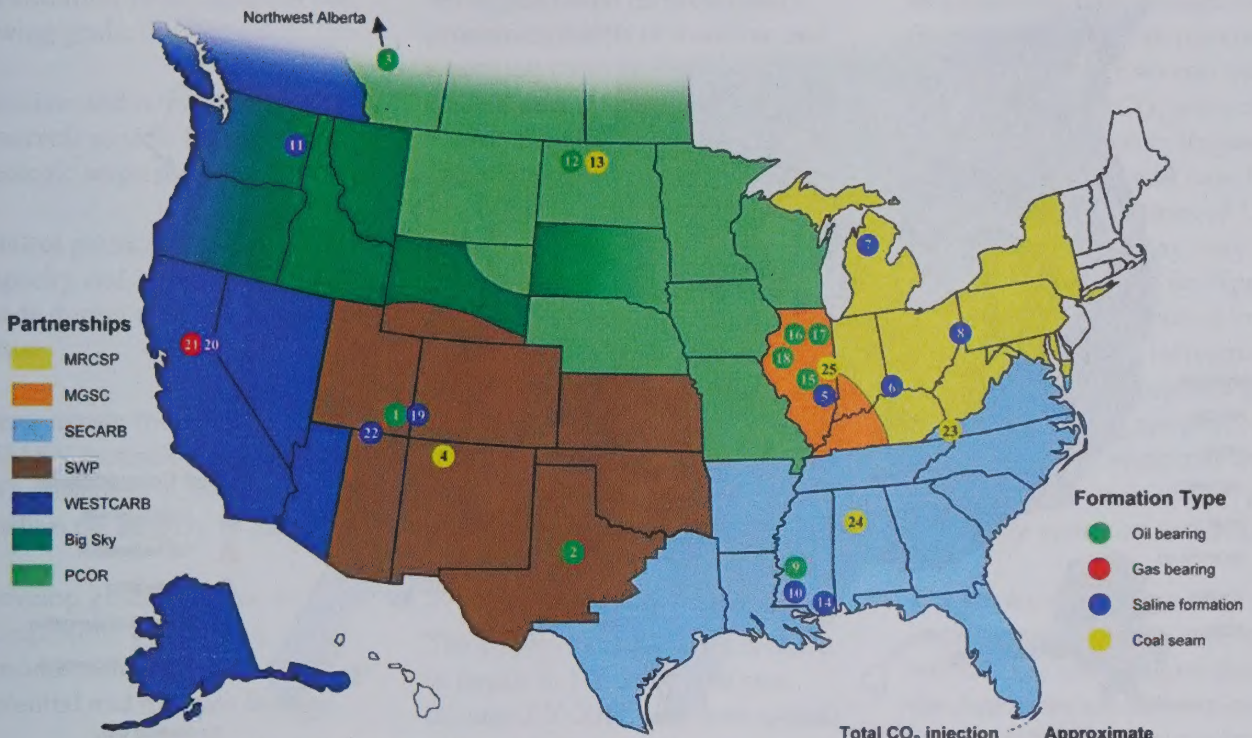


- **Capture: Given the substantial regulatory framework that currently addresses emissions standards, there is little need for state regulatory frameworks in this area. However, standards for measuring CO_2 concentration at the point of capture to verify quality should be devised.**

- **Transportation: Current well-established regulations and pipeline construction and material standards will adequately address CO_2 transportation.**

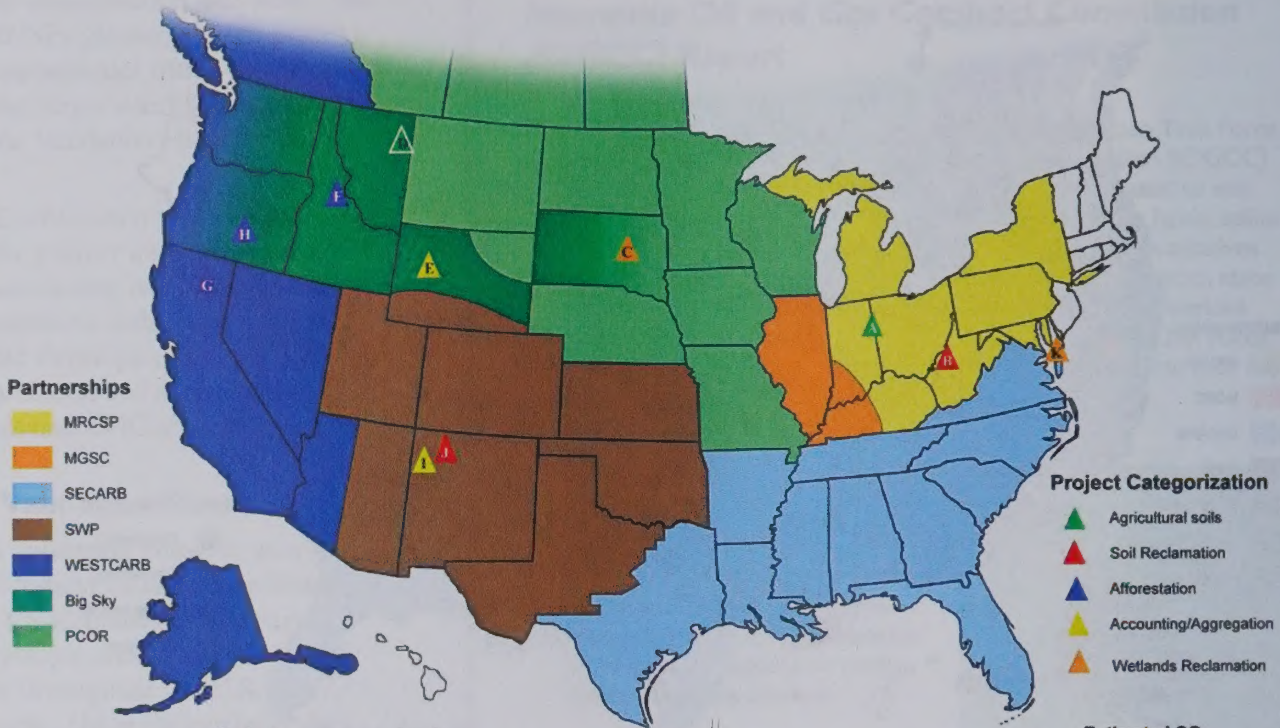
- **Injection: States and provinces with natural gas storage statutes should be able to utilize their existing natural gas regulatory frameworks, with appropriate modifications, for carbon capture and storage. A Class II permitting framework already exists under EPA and state Underground Injection Control (UIC) programs for oil and natural gas and could be used to address CO_2 injection into oil and natural gas reservoirs.**

- **Post Injection Storage: Following completion of CO_2 injection, a regulatory framework needs to be established to address monitoring and verification of emplaced CO_2, leak mitigation for the stored CO_2, and determination of long-term liability and responsibility.**



	Partnership	Geologic Province	Formation Type	Total CO_2 injection (tons CO_2)	Approximate Depth (feet)
1	SWP	Paradox Basin, Aneth Field	Oil-bearing	450,000 – 750,000	5,600 – 5,800
2	SWP	Permian Basin	Oil-bearing	900,000	5,800
3	PCOR	Keg River Formation	Oil-bearing	250,000 tons CO_2 w/90,000 tons H_2S	5,000
4	SWP	San Juan Basin	Coal seam	75,000	3,000
5	MGSC	Illinois Basin	Saline formation	10,000	7,000 – 8,600
6	MRCSP	Cincinnati Arch	Saline formation	1,000 – 3,000	3,200 – 3,500
7	MRCSP	Michigan Basin	Saline formation	3,000 – 20,000	3,200 – 3,500
8	MRCSP	Appalachian Basin	Saline formation	1,000 – 3,000	5,900 – 8,300
9	SECARB	Gulf Coast	Oil-bearing	500,000	10,066
10	SECARB	Gulf Coast	Saline formation	30,000	10,300
11	Big Sky	Columbia Basin	Saline formation (basalt/mafic)	3,000	3,255 – 3,335 & 3,600 – 3,755
12	PCOR	Duperow Formation	Oil-bearing	5,000	10,000 – 10,500
13	PCOR	Williston Basin	Coal seam	<1,000	1,600 – 1,800
14	SECARB	Mississippi Salt Basin	Saline formation	3,000	8,600
15	MGSC	Illinois Basin	Oil-bearing – Heavy	300	1,550
16	MGSC	Illinois Basin	Oil-bearing – Well Conversion	300	1,549
17	MGSC	Illinois Basin	Oil-bearing – Pattern Flood I	300	1,548
18	MGSC	Illinois Basin	Oil-bearing – Pattern Flood II	300	1,551
19	SWP	Paradox Basin, Aneth Field	Saline formation	20,000	6,900
20	WESTCARB	Thorton Gas Field	Saline formation	1,000	3,400 – 3,500
21	WESTCARB	Thorton Gas Field	Gas-bearing	500	3,050
22	WESTCARB	Colorado Plateau	Saline formation	2,000	5,000
23	SECARB	Central Appalachian	Coal seam	1,000	1,600 – 2,300
24	SECARB	Black Warrior Basin	Coal seam	1,000	1,500 – 2,500
25	MGSC	Illinois Basin	Coal seam	750	1,000

Figure 22. Regional Carbon Sequestration Partnerships Validation Phase Geologic Field Tests



Partnership	Project Location	Land Categorization	Project Summary	Estimated CO_2 Capacity
A MRCSP	Region-wide	Agricultural	Demonstrating carbon sequestration on existing farm lands. Determine rate of sequestration and potential for different tillage practices to increase storage.	250 Mt over 20 years
B MRCSP	Region-wide	Mineland	Demonstrating carbon sequestration in reclaimed mine soils. Determine reclamation and land management practices that increase storage.	100 Mt over 20 years
C PCOR	Great Plains wetlands complex (PPR)	Wetlands	Sequestration demonstration in wetlands/grasslands that will provide carbon offsets, develop protocols and standards, and provide a market-based carbon sequestration strategy.	14.4 Mt
D Big Sky	North Central MT	Agricultural	Objectives are to (1) quantify and determine cropland management practices that optimize carbon sequestration and (2) develop MMV protocols to evaluate carbon sequestration for enrolled farms.	60 Mt over 20 years
E Big Sky	Eastern WY	Rangeland	To determine the sequestration effects of (1) grazing intensity and seasonality of grazing on native northern mixed grass prairie and (2) improvement practices on degraded northern mixed-grass prairie.	30 Mt over 10 years
F Big Sky	Region-wide	Forest	Identify strategies for maintaining or increasing sequestration in forests through understanding the effects of forest management on different carbon pools in forests.	640-1,040 Mt over 80 years
G WESTCARB	Shasta County, CA	Forest and Rangelands	Validation of forest growth potential for rangelands; Change in forest management; Fuels management to reduce risk of uncharacteristically severe wildfire and prevent emissions	4,600 Mt over 80 years (CA)
H WESTCARB	Lake County, OR	Forest and Rangelands	Afforestation using fast-growing tree species; Fuels management to reduce risk of uncharacteristically severe wildfire and prevent emissions	900 Mt over 80 years (OR)
I SWP	Region-wide	Multiple	Develop a carbon reporting and monitoring system that functions consistently across hierarchical scales and is compatible with the existing technology underlying the 1605b reporting system. Project will develop improved technologies and systems for direct measurement.	TBD
J SWP	San Juan Basin Coal Fairway (Navajo City, NM)	Rangeland/ Riparian	Desalinate produced water from the ECBM pilot and use the water for irrigating a riparian restoration project. Reintroducing woody plant species along riparian areas and reestablishing native grasses and shrubs in upland areas. Project represents a combined ECBM-terrestrial sequestration project.	TBD
K MRCSP	Cambridge, MD	Wetlands	Develop estimates of carbon sequestration rates in marshes over time. Understand influences of carbon management practices on sequestration rates. Develop sampling protocol for sequestration validation.	TBD

Figure 23. Regional Carbon Sequestration Partnerships Validation Phase Terrestrial Field Tests

The field tests conducted during the Validation Phase address the following goals:

- Validate and refine current CO_2 reservoir models for various geologic sequestration sites
- Collect physical data to confirm capacity and injectivity estimates made during the Characterization Phase
- Demonstrate the effectiveness of MM&V technologies to measure CO_2 movement in the reservoirs and confirm the integrity of the seals
- Develop guidelines for well completion, operations, and abandonment to maximize storage potential and mitigate leakage
- Develop strategies that can be used to optimize the storage capacity for various sink types

To achieve these primary Validation Phase goals, each RCSP has further established its own supporting goals. Many of these supporting goals and actions were created as a logical continuation of goals completed and/or specific accomplishments attained during the Characterization Phase. The RCSPs are part of a programmatic initiative that is closely coordinated through DOE and the Working Groups.

In addition to the goals related to the field test projects, the RCSPs continue to improve on the work conducted during the Characterization Phase. The RCSPs will update information collected on CO_2 stationary sources and potential sequestration sites as additional data and analytical procedures become available. A common economic modeling approach for CO_2 capture will be developed based on preliminary economic models of available and emerging capture technologies created during the Characterization Phase. Storage capacity estimates for saline formations will be refined in the Validation Phase and beyond using a common methodology developed by the RCSPs during the Characterization Phase. Instrumentation evaluated and tested during the Characterization Phase to follow CO_2 injection, plume migration, and leak detection will be used to develop protocols for site selection and monitoring.

5. Deployment Phase

The Deployment Phase, scheduled to begin in FY 2008 and run through FY 2017, will demonstrate at large scale that CO_2 capture, transportation, injection, and storage can be achieved safely, permanently, and economically. DOE will provide up to $470M in federal support for the RCSPs over 10 years. An additional 20 percent cost share will be provided by each RCSP.

These large-volume deployment tests will provide concurrent input to the FutureGen Initiative, which will produce both hydrogen and electricity from a highly efficient and technologically sophisticated power plant while capturing and sequestering the CO_2 emissions. The geologic structures to be tested during these large-volume sequestration tests could become candidate sites for future near zero emissions power plants.

The primary goal of the Deployment Phase is the development of large-scale CCS projects across North America, where large volumes of CO_2 will be injected into a geologic formation representative of a relatively large storage capacity for each Region. The injection will continue over several years. Recognizing that CO_2 sources vary widely from Region to Region and that some Regions will have limited access to large volumes of CO_2, injection volumes may vary. The RCSPs, however, will be expected to maximize CO_2 injection volumes that fully utilize the infrastructure of the Region. Projects that procure CO_2 from natural gas processing plants or natural vents may inject one million tons or more of CO_2 per year, depending upon cost and availability.

The Deployment Phase tests will be implemented in three stages which will test key technologies during the demonstration and deployment: (1) site selection, characterization, National Environmental Policy Act (NEPA) compliance, permitting, and infrastructure development; (2) CO_2 injection and monitoring operations; and (3) site closure, post injection monitoring, and analysis. While projects in the Validation Phase are designed to demonstrate that regional sequestration sites have the potential to store thousands of years' worth of CO_2 emissions in the U.S., the large-volume sequestration tests in the Deployment Phase will also address practical issues such as sustainable injectivity, well design for both integrity and increased capacity, and reservoir behavior with respect to prolonged injection. Such issues can only be addressed by scaling up the size and duration of sequestration projects. Key operational issues and lessons learned will vary since each Region will have different geologic formations, overlying seals, and structural issues that can affect the safe and effective storage of CO_2 for millennia.

C. NETL Office of Research and Development

NETL conducts carbon capture and storage R&D through its Office of Research and Development (ORD) in four focus areas – Computational and Basic Sciences, Energy System Dynamics, Geological and Environmental Systems, and Materials Science – that build upon NETL R&D strengths and address long-range issues central to continued fossil fuel use. Science-based research and analysis in areas relating specifically to CCS is conducted within the Geological and Environmental Systems focus area and is known as the NETL Carbon Management Research Program.

Using in-house facilities and resources, researchers in the Carbon Management Research Program conduct the research and analysis needed to develop energy-efficient and cost-effective methods that can manage CO_2 emissions from energy production. NETL has established unique Centers of Research in carbon capture, permanent storage, and risk assessment associated with CCS technology development. These Centers of Research directly support the Carbon Sequestration Program as well as collaborative efforts with the RCSPs. Examples of ongoing interactions between the Centers of Research and the RCSPs include risk assessments with the Southwest Regional Partnership, CO_2 storage verification in coal seams with the Southeast and Southwest Regional Partnerships, and coal swelling modeling with the Midwest Geological Sequestration Consortium.

The NETL Center for Carbon Capture develops and evaluates breakthrough approaches that have the potential to substantially reduce the complexity and energy intensity of CO_2 capture. Research in this Center focuses on novel or revolutionary approaches that remove CO_2 during energy production rather than scrubbing or eliminating it from a by-product stream. The development of membranes to separate CO_2 from combustion gases is one example of this research; once separated, the CO_2 is easily captured and can then be sequestered. Oxy-fuel firing is another process under development, whereby CO_2 can be separated from exhaust gases by simply condensing out the water. Researchers often use a combination of laboratory studies and numerical models to evaluate novel approaches to carbon capture. Relying on their expertise in modeling and simulation, researchers extrapolate laboratory findings to projected applications before engaging in large-scale testing.

The Center for Permanent Storage is researching several CO_2 storage verification techniques, including soil gas measurements;

Monitoring Techniques for Sequestered CO_2

Research aimed at monitoring the stability and integrity of CO_2 sequestered in geologic formations is one of the most pressing needs in ensuring that Carbon Sequestration Program objectives are met. Techniques include monitoring perfluorocarbon tracers added to the injected CO_2 and detected in soil-gas at parts per quadrillion levels, shallow water aquifer chemistry changes, CO_2 flux at the surface, and natural tracers in soil-gas.

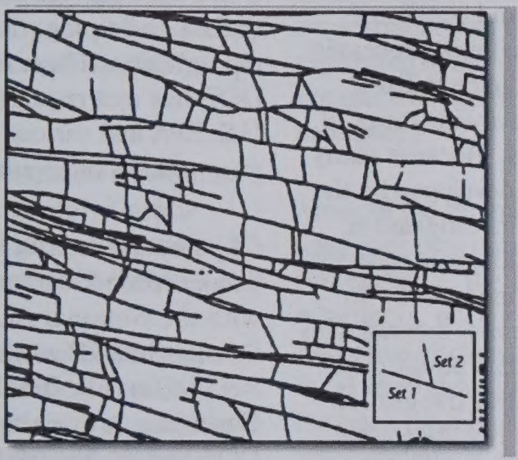
Perfluorocarbon Tracers are Added to CO_2 as it is Injected at the Frio Test Site Near Houston, TX

Researchers have successfully tested perfluorocarbon tracers at the West Pearl Queen depleted oil well sequestration test site in New Mexico and at the Frio saline formation sequestration test site near Houston, Texas. Used in conjunction with ground-penetrating radar, these tracers are part of an entire suite of monitoring techniques now being used to evaluate the long-term retention of CO_2 in underground formations. In general, surface and near-surface monitoring have been successfully applied in semiarid soil and heavily forested, swampy site conditions.

characterization of surface fault exposures; computer tomography scanning of cores to assess fractures and rate of diffusion of CO_2 into the strata; groundwater sampling and analysis; aeromagnetic flyover surveys for existing and abandoned wells, and adsorption isotherm studies of relevant strata. These technologies are currently in use at RCSP field sites to ensure that permanent storage of CO_2 is attained at low cost, with low environmental impact, and in conformity with national and international laws. In support of the RCSP efforts to select sequestration sites and estimate storage capacity, the Center for Permanent Storage is developing a suite of modeling techniques to quantify CO_2 flows in deep subsurface reservoirs, through intermediate strata, and near the ground surface. Models under development include near-surface modeling of CO_2 flow to aid in designing and interpreting results from monitoring networks, modeling of flow through actual fractures to better understand flow phenomena, and unique fracture generation and flow simulation software to model flow through intermediate strata and through the target reservoir.

The Center for Risk Assessment is working to identify risks associated with the permanent storage of CO_2. A main component of the Center's risk assessment activity will be to identify the risks associated with field projects through the use of features, processes, events, and models that have been developed for risk assessments elsewhere. Initially, the analyses will be based on the field sequestration projects being undertaken by the RCSPs. This approach will correlate modeling and monitoring techniques with the risk assessment model to identify potential events and probabilities of events affecting CO_2 storage. Development of a carbon storage risk assessment capability is expected to provide a valuable tool that can be used to support the performance of environmental assessments and impact studies of carbon capture and long-term storage options. Risk assessment results will also help in informing the public about the safety of carbon capture and storage.

ORD efforts offer in-depth scientific expertise that can be applied to the development of new technologies, processes, and models that are



Typical Reservoir Fracture Pattern, MWX Site.

Coal Seam Simulators

CO_2 sequestration in unmineable coal seams uses otherwise uneconomic resources, permits the production of natural gas from the coal seams, and prevents CO_2 from entering the atmosphere. NETL researchers have already developed FORTRAN-based codes that generate a reasonable fracture pattern for a gas reservoir (FRACGEN) and that solve the material balance for compressible fluid flow in the rock matrix and fractures of the reservoir (NFFLOW). However, to address issues such as how much CO_2 could be sequestered in coal seams, where injection and withdrawal wells should be placed, how much natural gas could be produced, and how much CO_2 leakage should be expected, modifications to the existing suite of reservoir simulation codes are required. For example, since the fracture network in a gas reservoir contains fewer but much longer and wider fractures than the system of cleats in a coal seam, FRACGEN must be modified to account for the coal seam fracture pattern. NFFLOW is being modified to account for two-phase flow in order to more realistically characterize the coal matrix geometry. Development work now focuses on coupled (flow and geomechanical) modeling as well as on migration of CO_2 both within and outside the target reservoir.

essential in meeting long-term program goals. It provides an impartial evaluation of new concepts, products, and materials that may be considered by the RCSPs for deployment, and offers a venue for participation in collaborative research by other research organizations (e.g., other national laboratories, universities, and technology developers).

D. Supporting Mechanisms

A number of supporting mechanisms contribute to the Carbon Sequestration Program and enhance its ability to meet Program objectives.

1. International Collaboration

The U.S. believes that technology provides the key to reduce GHG emissions. Formed in 2003, the Carbon Sequestration Leadership Forum is one such technology forum. CSLF international members engage in cooperative technology development aimed at enabling the early reduction and steady elimination of CO_2 emissions from electricity generation and other heavy industrial activity. Members are dedicated to collaboration and information sharing to foster the worldwide deployment of multiple technologies for the capture and long-term geologic storage of CO_2 and to establishing a companion foundation of legislative, regulatory, administrative, and institutional practices that will ensure safe, verifiable storage for millennia. The CSLF technology roadmap identifies research and development pathways that lead to commercially viable carbon capture and sequestration systems.

The CSLF has recognized 17 international research, development, and demonstration projects to advance technologies for low-cost CCS. DOE's efforts in the sequestration arena are recognized by the formal endorsement of FutureGen and the RCSP field tests as CSLF projects.

2. Systems and Benefits Analyses

Systems analyses and economic modeling of potential new processes provide crucial guidance to R&D efforts investigating a wide range of CO_2 capture options. Because many of the technologies developed by the Program are being investigated at the laboratory or pilot-scale, systems analyses offer an opportunity to visualize how these new technologies might fit in a full-scale power plant and identify potential integration issues. Analytical results enable decision makers to determine which technologies merit continued funding and how research can be modified to enhance technology success at full-scale.

Modeling tools aid systems analysis efforts. For example, the Integrated Environmental Control Model (IECM) enables systematic cost and performance analyses of emission control equipment at coal-fired power plants. Users can evaluate plant configurations using a variety of pollutant control technologies, including options for CO_2 capture (amine and Selexol scrubber, water-gas shift reactor, and O_2-CO_2 recycle), pipeline transport, and storage. The Program also participates in cross-cutting studies to consider how sequestration might help meet future CO_2 emissions reductions goals. These broader efforts often rely on large models such as the DOE National Energy Modeling System (NEMS).

3. Interagency Coordination

In each sequestration research area, DOE collaborates closely with other agencies. For example, in the area of terrestrial sequestration, the Program is working closely with the U.S. Forest Service and the Office of Surface Mining. To prepare for the Validation Phase of the RCSPs, DOE has met regularly with the U.S. EPA and various state and local governments on regulatory issues.

Of particular interest, the Carbon Sequestration Program collaborated with the National Academy of Sciences in 2003 and 2004 to bolster R&D efforts in Breakthrough Concepts. A workshop hosted by DOE and the National Research Council (NRC) identified priorities for breakthrough research, and a subsequent solicitation produced a pool of more than 100 proposals. Eight awards were made in March 2004 and research work is proceeding. Information from the workshop was also used in a funding opportunity announcement on capture technology released in FY 2006.

4. Education and Outreach

Carbon capture and storage is a relatively new scientific and technology discipline; as such, many people are unaware of its role as a GHG mitigation strategy. Increased education and awareness are needed to improve its acceptance by the general public, regulatory agencies, policy makers, and industry,

and to enable future commercial deployment of advanced carbon sequestration technology. Activities highlighting the Program education and outreach efforts include:

- Carbon Sequestration webpage on the NETL website (http://www.netl.doe.gov/technologies/carbon_seq/index.html)
- Carbon Sequestration Technology Roadmap and Program Plan – revised annually (http://www.netl.doe.gov/publications/carbon_seq/refshelf.html)
- Carbon Sequestration Newsletter – distributed monthly (http://www.netl.doe.gov/publications/carbon_seq/subscribe.html)
- Middle School and High School Educational Curricula on GHG Mitigation Options – disseminated through workshops at National Science Teacher Association conferences (http://www.keystonecurriculum.org/)
- Carbon Offsets Opportunity Program website (http://www.offsetopportunity.com)
- The annual National Conference on Carbon Capture and Sequestration. (http://www.carbonsq.com/)

In addition, the Program team participates in technical conferences through presentations, panel discussions, breakout groups, and other formal and informal venues. These efforts expose professionals working in other fields to the technological challenges facing sequestration and foster discussions regarding some of the more complicated issues underlying CCS technology.

Many of the Program R&D projects have their own outreach component. For example, the RCSPs engage regulators, policy makers, and interested citizens at the state and local level through innovative outreach mechanisms. The RCSPs also implement action plans for public education in the form of mailing lists, public meetings, media advertising, local interviews, and education programs available at libraries, schools, and local businesses.

Carbon Sequestration-Related Web Pages

National Energy Technology Laboratory	**http://www.netl.doe.gov/sequestration**
U.S. Department of Energy, Office of Fossil Energy	**http://www.doe.gov/sciencetech/carbonsequestration.htm**
Carbon Sequestration Leadership Forum	**http://www.cslforum.org/**
West Coast Regional Carbon Sequestration Partnership	**http://www.westcarb.org/**
Southwest Regional Partnership on Carbon Sequestration	**http://www.southwestcarbonpartnership.org/**
Big Sky Carbon Sequestration Partnership	**http://www.bigskyco2.org/**
Plains CO_2 Reduction Partnership	**http://www.undeerc.org/pcor/**
Midwest Geological Sequestration Consortium	**http://www.sequestration.org/**
Midwest Regional Carbon Sequestration Partnership	**http://198.87.0.58/default.aspx**
Southeast Regional Carbon Sequestration Partnership	**http://www.secarbon.org/**

If you have any questions, comments, or would like more information about DOE's Carbon Sequestration Program, please contact the following persons:

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Appendix F

Memorandum Between White Pine Energy Associates, LLC and State of Nevada

MEMORANDUM OF UNDERSTANDING

BETWEEN

WHITE PINE ENERGY ASSOCIATES, LLC

AND

STATE OF NEVADA

This Memorandum of Understanding ("MOU") between White Pine Energy Associates, LLC ("the Company") and the State of Nevada (State of Nevada – Department of Conservation & Natural Resources – Division of Environmental Protection or "NDEP") (each, a "Party" and collectively the "Parties") is entered into as of November 20, 2007.

I. RECITALS

WHEREAS, the Company has proposed to construct an electrical generation facility in White Pine County, Nevada (the "Facility"). The Facility would produce electricity using coal. As with the combustion of any fossil fuel, by using coal, the Facility will produce carbon dioxide ("CO2") emissions. CO2 is a greenhouse gas ("GHG").

WHEREAS, there is concern that an increase in world-wide GHG emissions may contribute to a change in global climate. How to address GHG emissions – while balancing energy demand, economic growth, and national security – is a matter of considerable debate. Based on currently applicable laws and regulations there are no requirements that would impose emissions limitations or controls on CO2.

WHEREAS, in the State of Nevada, the matter of GHG's is presently under review. By Executive Order on April 10, 2007, Governor Jim Gibbons formed a 15-member Nevada State Climate Change Advisory Committee. The Committee represents a wide spectrum of viewpoints in Nevada and is charged with providing a final report and recommendations to the Governor on how Nevada may further reduce GHG emissions, including through the use of renewable energy sources.

WHEREAS, the State of Nevada recognizes that electrical energy generation from coal is an important part of a diversified energy portfolio, providing greater assurance of sufficient, reliable, and cost-effective electrical energy.

WHEREAS, at present, there is no large scale technology, currently available, to capture CO2 emissions ("CO2 Capture technology") from facilities of this type. Nor are there commercial prototypes of CO2 Capture technology available for such facilities. The Parties believe, however, that the Facility can be designed and constructed to be "Carbon Capture Ready" so that

the Facility may in the future be retrofitted to capture CO2 emissions and sequester and/or appropriately manage the emissions in a suitable manner when CO2 Capture technology is demonstrated to be feasible and commercially available and can be implemented in a cost effective manner.

NOW, THEREFORE, and in consideration of the foregoing, the Company and NDEP enter into this MOU, whereby, the Company commits to use commercially reasonable efforts to design the Facility in a manner that is "Carbon Capture Ready".

II. COMMITMENT FOR CARBON CAPTURE READY FACILITY

A. Facility Covered By the MOU. The Company is proposing to build the following Facility in Nevada subject to this MOU: an approximately 1590-megawatt supercritical coal-fired power plant in White Pine County, Nevada commonly known as the White Pine Energy Station.

B. Other Facilities. NDEP will engage and negotiate with any applicant for a new coal-fired power plant in an effort to secure an MOU establishing a commitment whereby such applicant agrees to the design, installation, and operation of carbon capture and sequestration consistent with this MOU. Therefore, the NDEP agrees that if other person(s) propose additional coal-fired power projects in this State (including projects proposed as of the date of this MOU), NDEP will seek to reach an understanding with those persons regarding CO2 Capture technology, as provided for in this MOU. If any new coal-fired facility goes forward with a less onerous commitment, a true and complete copy of such commitment shall be provided to the Company and the less onerous aspects of such commitment will replace such commitment in this MOU. If any new coal-fired facility in the State of Nevada is allowed to proceed without such a commitment, this MOU will terminate effective immediately and without further action of the Parties upon the commencement of on-site construction of such facility.

C. The Company's commitment to "Carbon Capture Ready" Facility.

1. CO2 Capture technology for coal fired power plants has not been demonstrated on a large scale and it is not yet commercially available. There are no commercial prototypes available at this time for facilities of this type. It is likely that significant improvements in CO2 Capture technology will occur before CO2 Capture technology is demonstrated on a large scale and is deemed commercially available. It is therefore understood and agreed that no CO2 Capture technology or method can or should be specified at this time.

2. The Company will, however, use commercially reasonable efforts to design and construct the proposed Facility in a manner intended to be "Carbon Capture Ready" (as defined herein) so that the Facility may be retrofitted in the future with CO2 Capture technology to capture and sequester and/or appropriately manage CO2 emissions from the Facility in a suitable

and safe manner. Specifically for purposes of this MOU, "Carbon Capture Ready" means that the Company will set aside real estate (approximately 7 acres of land per pulverized coal boiler) in the general vicinity of the pulverized coal boiler(s) stack(s) to allow for the design, installation and operation of future CO_2 capture equipment and will design the Facility such that ducting can be configured and constructed to divert exhaust gases to a CO_2 capture system.

3. The Company's commitment to construct a Carbon Capture Ready plant is contingent on the Company receiving all necessary permits and approvals and financing for the Facility. The commitment is also subject to the Company's own independent decision to proceed with the Facility.

4. Subject to receiving all necessary permits and approvals for the implementation of the CO_2 Capture technology and sequestration ("CC&S"), the Company will, except as otherwise provided herein, design, construct, install and operate CO_2 Capture technology at its Facility, when a final determination has been reached in accordance with this section that such technology and associated sequestration has been demonstrated to be technologically feasible on a large scale basis and is deemed commercially viable for the White Pine Energy Station. A preliminary determination of technical feasibility and commercial viability for White Pine Energy Station will be made by the NDEP based on its assessment of advances in the development of CC&S technology and the actual deployment and operation of carbon capture equipment, sequestration viability including the location of areas in which carbon emissions from the White Pine Energy Station might be sequestered, the transport of carbon to such locations, the direct application of the foregoing to the White Pine Energy Station and other relevant information. In making its preliminary determination, NDEP will evaluate information and analyses regarding the state of development of CC&S technology. Such information and analyses may include but are not limited to information and analyses generated by the U.S. Environmental Protection Agency, the U.S. Department of Energy National Energy Technology Laboratory, and the West Coast Regional Carbon Sequestration Partnership (known as WESTCARB).

Following a preliminary determination that CC&S is technically feasible and commercially viable for the White Pine Energy Station, NDEP shall notify the Company of its preliminary determination and the basis for such determination. The Company will evaluate such determination and may (i) concur with the determination and proceed with implementing CC&S consistent with the terms of this MOU, (ii) seek clarification of NDEP's basis for its determination of technical feasibility and commercial viability, or (iii) provide NDEP with additional information and analysis relevant to the technical feasibility and commercial viability of CC&S.

In the event that the Public Utility Commission of Nevada ("PUCN") makes a determination that CC&S is commercially available for a similarly situated project in Nevada and as a result such project has committed to implement CC&S, such determination will establish a presumption that CC&S is commercially available for the Facility unless the Company provides a written response rebutting such presumption. The written response must be made within ninety (90) days of the Company's receiving notice of a preliminary determination from NDEP finding that CC&S is

commercially available for the Facility. The Company's written response must set forth with particularity any distinguishing factors between the plant for which the PUCN determined CC&S to be commercially available and the Facility, including but not limited to the respective designs of the plants as the same might enhance/limit the application of CC&S technology, the locations of the plants relative to carbon sequestration opportunities, and other energy, environmental and economic factors associated with CC&S technology as applied to the Facility.

At the request of either Party, input from a mutually agreed third party engineering consultant with expertise in CC&S technology shall be received in order to inform the determination. A final determination of the technical feasibility and commercial viability of CC&S will require a consensus agreement between NDEP and the Company. Any final determination shall be made consistent with then-current applicable laws and regulations. If the Parties can not reach consensus, NDEP will initiate a rulemaking process on this issue in accordance with the Nevada Administrative Procedure Act.

5. In addition, the Parties anticipate that the applicable legal requirements may be very different at the time a final determination may be made that CC&S is technically feasible and commercially available. Accordingly, notwithstanding the commitment set forth in paragraph C(4) above, in the event that state or federal laws regulating CO2 emissions, including the establishment of CO2 emission limitations, CO2 capture and storage requirements, or the establishment of a cap-and-trade or carbon tax program, are enacted that are applicable to the Facility, the Company's compliance with such laws will satisfy and supersede the commitment set forth above and this MOU shall terminate. For purposes of this paragraph, laws regulating CO2 emissions shall not be deemed to include laws that simply create GHG monitoring and reporting requirements or laws that impose other, nonsubstantive or administrative requirements. If either of the Parties believes that changes in state or federal law have occurred that may result in termination of this MOU, the Parties agree to meet and discuss the change(s). The Parties agree to compare the change(s) in state or federal law with the requirements of this MOU. The MOU will not be terminated if the Parties agree that the change in state or federal law results solely in a GHG monitoring and reporting requirement or a nonsubstantive or administrative requirement.

6. The Parties agree that nothing in this MOU should be read to require the environmental impact statement for the Facility to consider CC&S in the course of the review of potential impacts of the proposed Facility.

7. This MOU is intended to be binding only as to the specific obligations of the Parties set forth herein. This MOU does not commit the Company to proceed with the implementation of CO2 Capture technology at the Facility, unless or until a final determination has been made subject to the conditions set forth in paragraphs C(4) and C(5) above.

D. Advancement of Research. The Parties acknowledge that much research is underway by the public, academic and private sector to advance CO2 Capture technology and to

increase understanding of sequestration opportunities. The NDEP encourages the Company to pool resources with the public, academic and/or private sector to advance such research. The Company will provide the NDEP with periodic reports summarizing the results of the research the Company, or its affiliates, are involved with that has the potential to be applicable to CC&S at the Facility.

III. MISCELLANEOUS

A. Notices. Any notices required under this MOU shall be in writing and shall be deemed to have been duly given if sent via a national overnight courier service or by certified mail, return receipt requested, postage prepaid, addressed to the Parties as follows:

Company: White Pine Energy Associates, LLC
Attn: Project Manager
400 Chesterfield Center, Suite 110
St. Louis, MO 63017
(636) 532-2200

White Pine Energy Associates, LLC
Attn: General Counsel
Two Tower Center, 11th Floor
East Brunswick, NJ 08816
(732) 249-6750

Nevada: State of Nevada – Division of Environmental Protection
Attn: Administrator
901 So. Stewart Street, Ste 4001
Carson City, NV 89701-5249
(775) 687-4670

State of Nevada – Division of Environmental Protection
Bureau of Air Quality Planning
Attn: Section Chief
901 So. Stewart Street, Ste 4001
Carson City, NV 89701-5249
(775) 687-9329

or to such other address as any party shall request of the others by giving written notice.

B. Amendments. This MOU may not be amended, changed or modified except by a written document signed by each of the Parties.

C. Limitation. Nothing contained in this MOU shall be construed as a defense

against any future statutory or regulatory requirement.

D. Regulations. Nothing in the MOU shall be deemed as prohibiting the State Environmental Commission from promulgating regulations applicable to greenhouse gas emissions and the Facility.

E. Successors and Assigns. This MOU shall apply to the Parties and their respective successors and assigns.

F. No Third Party Beneficiaries. This MOU is intended for the sole benefit of the Parties, and the Parties do not intend to create any other third party beneficiaries or otherwise create privity of contract with any other person.

G. Authorized Representative. Each undersigned representative of the Parties certifies that he or she is fully authorized to enter into this MOU and to execute this document for the Party he or she represents.

H. Counterparts. This MOU may be executed in separate counterparts, each of which is deemed to be an original and all of which taken together constitute one and the same agreement.

[The remainder of this page is intentionally left blank.]

NOW, THEREFORE, and in consideration of the foregoing, the Company and NDEP enter into this MOU, whereby, the Company commits to use commercially reasonable efforts to design the Facility in a manner that is "Carbon Capture Ready".

STATE OF NEVADA [acting by and through the Nevada Division of Environmental Protection]

Leo M Drozdoff 11/20/07

Name: Leo M. Drozdoff Date

Title: Administrator

WHITE PINE ENERGY ASSOCIATES, LLC

Paul G. Thessen 11/20/07

Name: Paul G. Thessen Date

Title: Vice President

Appendix G

Ground Water Monitoring Program

APPENDIX G

Ground Water Monitoring Program

White Pine Energy Associates, LLC (WPEA) is committed to adopt the procedures outlined in the following ground water monitoring program should the White Pine Energy Station project be approved and implemented. The objective of this monitoring plan is to describe the water resources monitoring activities in response to the annual ground water withdrawal of 5,000 acre-feet (af) from the basin-fill aquifer in the Steptoe Valley, associated with the proposed White Pine Energy Station (the Station) to be located in Steptoe Valley, White Pine County, Nevada.

Although this demand for water would be the same for either the Proposed Action or Alternative 1, the demand would be met through the operation of two different well fields each consisting of eight water supply wells located in an approximate linear configuration on the valley floor, roughly parallel to U.S. 93 (see Chapter 2, *Description of Ground Water Resources*). Specifically, for the Proposed Action, the eight wells in the proposed well field are located at intervals of between approximately 1 and 3 miles extending from the proposed energy station location northward for approximately 12 miles. The eight wells in the proposed wellfield for Alternative 1 are located at intervals of between approximately 1 and 2.5 miles extending from the Alternative 1 energy station location south for approximately 5 miles.

The ground water monitoring program will be a part of the adaptive management plan, which will be incorporated in the Plan of Development or Construction, Operation, and Maintenance Plan that BLM will require from WPEA before a notice to proceed with construction is granted. The ground water monitoring program, which would be managed by WPEA, would document changes in ground water levels and provide early warning for unanticipated reductions in spring discharge at selected springs that could be caused by the ground water withdrawals for the Station. These reductions have the potential for adverse impacts to resources in the surrounding environment. The program also identifies the general procedures that would be followed in response to changes in measured ground water levels.

Certain parameters of this ground water monitoring program, including monitoring frequency and sample location will be initially established in consultation with the State Engineer. These parameters will be reviewed annually and may be reduced or expanded in scope upon the recommendation of the State Engineer and/or the Nevada Division of Environmental Protection.

Production Wells

Discharge rates and ground water levels will be measured in each of the production wells on a continuous or frequent basis, as is practical, using permanent recording devices. The water levels would be measured during pumping and non-pumping periods.

Depth to ground water will be measured in all production wells daily using pressure transducers or sounding probes. Each production well will be equipped with a flow meter to

record cumulative water production. Cumulative well production will be recorded at least monthly. All monitoring data will be entered into a project database maintained by White Pine Energy Associates, LLC.

Monitoring Wells

For the Proposed Action, a network of up to ten wells will be installed prior to Station start-up and monitored for water level change on a frequency that will be determined in coordination with appropriate agencies. For Alternative 1, up to four monitoring wells are anticipated to be installed and monitored. The general locations of the monitoring wells are identified for the Proposed Action in Figure G-1, and for Alternative 1 in Figure G-2. The specific locations of the monitoring wells will be determined based on physical access limitations and the specific characteristics (for example, depth and screen interval) and performance of the production wells, which will not be known until they are installed and tested. All of the monitoring wells are anticipated to be located on public land or property owned by WPEA.

The wells would be constructed with screen intervals sufficient to monitor both shallow (unconfined) ground water levels that could influence spring discharge, and deeper ground water that is more representative of existing water supply wells completed in the basin-fill aquifer system in Steptoe Valley. The specific locations and well construction details will be presented in a plan to the Office of the Nevada State Engineer upon completion and pump testing of the production wells.

Ground water levels will be measured on a frequency that will be determined in coordination with appropriate agencies, using dedicated recording devices in selected monitoring wells. For those monitoring wells without continuous monitoring instruments, water levels will be measured quarterly initially to establish seasonal variations, followed by semiannual or annual measurements after seasonal trends have been established.

White Pine Energy Associates may determine that additional monitoring well(s) should be installed in areas where there are no existing or proposed wells available for monitoring. These additional wells will be located and constructed in a cost-effective manner, while meeting the objectives of early-warning detection of impacts, if any, from proposed ground water extraction.

Initiation of ground water level monitoring will commence as soon as possible, recognizing the desire to obtain baseline data prior to ground water extraction.

Elevation Control

Ground surface and measuring point elevations will be measured at each production and monitoring well using a survey-grade GPS instrument. All elevation measurements will be added to the project database that contains ground water level data.

Springs

Selected springs in Steptoe Valley identified in Figure G-1 will be monitored quarterly. Monitoring will consist of measuring flow rate and photo-documenting general site conditions. Flow will be estimated for low flow conditions or where the flow is diffuse on the ground surface. Monitoring frequency may be reduced later as appropriate to semi-annually or annually.

Initiation of monitoring for springs will commence as soon as possible, recognizing the desire to obtain baseline data prior to ground water extraction. Monitoring data will be recorded using a standard format to be used for each monitoring event.

Water Quality

Ground water quality samples will be collected from all eight production wells and selected monitoring wells, and analyzed by a laboratory for major ions and trace elements.

Specifically, the following parameters will be measured in each water sample:

- **Field Parameters.** Water temperature, pH, oxidation-reduction potential (ORP) and specific conductance.
- **Common Ions.** Calcium, sodium, potassium, magnesium, chloride, fluoride, sulfate, bicarbonate, nitrate, total dissolved solids, and total suspended solids.
- **Trace Elements.** Arsenic, barium, copper, iron, lead, manganese, and zinc.

More extensive water quality analysis will be performed for the portion of water from the production wells used as potable water at the Station. Samples from this water will meet Safe Drinking Water requirements, as appropriate.

Ground water quality samples will be collected and analyzed quarterly from the selected monitoring wells and production wells for the first 2 years following start-up to establish seasonal variations. Thereafter, the wells will be sampled and analyzed at a maximum frequency of semiannually (spring and fall), or as required by drinking water requirements for public sources.

Frequency, sampling location, and water quality parameters will be reviewed annually and may be reduced or expanded in scope upon the recommendation the Nevada Division of Environmental Protection.

Ground water quality monitoring programs also will be conducted on the power plant site at the solid waste disposal facility and the evaporation pond. These two monitoring programs are described briefly in the following text.

The **ground water quality monitoring program for the solid waste disposal facility** will consist of eight wells. Three wells will be located upgradient of the disposal facility to obtain samples representative of background water quality. Five wells will be located downgradient of the disposal facility to ensure the detection of potential contaminants. Samples will be collected quarterly at the eight wells during project operation and into the post-closure period

and analyzed for a list of targeted elements of environmental concern associated with Powder River Basin coal. This ground water quality monitoring program and other environmental protection measures at the solid waste disposal facility are outlined in the Operations Plan, Closure Plan, and Post-Closure Plan (SRK Consulting, 2006b), *Permit Application White Pine Energy Station Class III Solid Waste Disposal Facility, White Pine County.*

The **ground water quality monitoring program for the evaporation pond** will consist of five wells. Two wells will be located upgradient of both the evaporation pond and the solid waste disposal facility to obtain samples representative of background water quality. Three wells will be located downgradient of the evaporation pond to ensure the detection of potential contaminants. Samples will be collected quarterly at the five wells during project operation and analyzed for a list of parameters specified in the evaporation pond permit issued by the Nevada Division of Environmental Protection's Bureau of Water Pollution Control. This ground water quality monitoring program and other environmental protection measures at the evaporation pond are outlined in SRK Consulting (2006a), *Evaporation Pond Design, Operation and Maintenance Manual, White Pine Energy Station White Pine County, Nevada.*

Reporting

In addition to updating the water resources project database on a regular basis, an annual summary report will be prepared by WPEA that summarizes all information collected during the previous calendar year, including an analysis of any trends in either ground water levels or spring discharge. This summary report will include all data collected under or as described in this Plan and will be submitted on an annual basis to the Office of the Nevada State Engineer, the Nevada Division of Environmental Protection, the US Bureau of Land Management, and White Pine County, Nevada.

Mitigation Actions

Upon completion of the water supply system to the Station, including all of the wells, piping and instrumentation, a comprehensive assessment of the potential production rates of each well would be conducted to develop an operational plan for the optimal pumping rates of each well in the well field. During full Station operation, should the pattern of ground water level decline in the monitoring wells indicate that the discharge from known springs may experience a potentially adverse reduction as a direct response to continued pumping and it is determined that the production well is the actual cause of that potential impact, action would be taken to adjust the amount and pattern of pumping in advance of spring discharge being adversely affected. Specifically, an alternative pumping distribution would be adopted to reduce the pattern of ground water level decline in the vicinity of the potentially affected springs in order to maintain spring discharge. The general locations of the monitoring wells have been identified to provide sufficient warning to enable time to adjust the pumping rates prior to known springs being affected.

Under both the Proposed Action and Alternative 1, a maximum of eight wells would be available to meet the annual water demand of 5,000 acre-feet. The average pumping rate would therefore be approximately 390 gallons per minute (gpm). Given what is currently

known about the aquifer, individual well yields on the order of 1,000 gpm should be attainable. Accordingly, not all eight wells would be needed if some of the wells had to decrease pumping to prevent known springs from being affected by project pumping. For example, if only six of the eight wells were to be used, then the average pumping rate would increase to approximately 515 gpm per well. This pumping rate should be attainable, but would need to be confirmed following well installation and testing.

However, should it be determined that no spatial or temporal combination of pumping required to meet the water demand of the Station could be achieved without resulting in a ground water level decline that could cause potentially adverse impacts to known springs, and it is determined that the production well is the actual cause of that potential impact, then WPEA would file applications with the appropriate agencies to obtain the necessary permits and approvals for the construction of alternative production wells and conveyance systems. In the interim, WPEA would work with the appropriate agencies, including the BLM, to mitigate the negative impact on the springs. Once alternative production wells and conveyance systems are in place, the water demand would be met using water from a combination of both existing and new wells in a manner that did not result in ground water level declines sufficient to cause adverse impacts to known springs.

Should drinking water standards be exceeded in any potable water sample from the production well system, the necessary steps would be taken to provide potable water to the Station. Should the necessary steps take an extended period of time to implement, bottled water will be brought to the Station for potable uses.

Proposed General Locations of Ground Water Level Monitoring Wells for the Proposed Action White Pine Energy Station Project

Figure G-1

Proposed General Locations of Ground Water Level Monitoring Wells for Alternative 1 White Pine Energy Station Project

Figure G-2

Appendix H

Alternative Coal-Fueled Generating Technologies

Report

Alternative Coal-Fueled Generating Technologies

Prepared for

U.S. Bureau of Land Management

Ely Field Office, Nevada

Contents

Section	Page

Background

The proposed action is an approximately 1,600-megawatt (MW) electric power plant, consisting of one to three supercritical pulverized coal-fired boilers that will produce steam for the steam turbine electric generator(s). Each generator is expected to have a nominal generating capacity of 500 MW to 800 MW. The boilers will be designed to maximize efficiency and minimize air pollution during the combustion process. Powder River Basin coal, a subbituminous coal, is expected to be the primary fuel for the facility, although other solid fuels may be used pending economic considerations and compliance with permitting limitations.

The three general categories of coal-fueled technologies considered in this report are as follows:

- Pulverized coal (PC) combustion technology (including subcritical, supercritical, and ultrasupercritical)
- Circulating fluidized bed (CFB) combustion technology
- Integrated gasification combined cycle (IGCC) technology

The purpose of this report is to provide information regarding these alternatives and the reasons why these alternatives were either carried forward or eliminated from detailed analysis. The following subsections evaluate each potential alternative, including assessments of the relevant technological, operating, efficiency, environmental, and economic issues.

The terms bituminous, subbituminous, lignite, waste coal and petroleum coke (petcoke) are used in this report to distinguish the different types of coals commonly used, as well as other solid fuels (petcoke). Definitions of the terms can be found in the Appendix A to this report. The classifications of coal are important, because the characteristics of solid fuels can vary greatly in terms of energy content, sulfur content, ash content, and moisture. Typically a specific solid fuel is selected for a power plant based on availability, transportation routes, costs, and environmental considerations. Once selected, the power plant will be designed to use this fuel over the life of the facility. A power plant may have the capability to burn coals other than the design fuel, but if the characteristics are significantly different, the power plant could be affected by one or more of the following:

- Reduced electric output
- Efficiency loss
- Increased maintenance and repairs
- Change in environmental performance

Pulverized Coal-Fired Combustion

Most coal-fired power plants in operation today use pulverized coal-fired boilers. Pulverized coal units use a proven technology that is capable of very high levels of reliability. There are two distinct categories of PC units: subcritical units and supercritical units. In a subcritical unit, steam is produced at pressures and temperatures below the critical point of the steam—steam conditions with a pressure below approximately 3,200 pounds per square inch (psi) and temperatures typically around 1,000°F. In a supercritical unit, supercritical steam fluid is generated at temperatures and pressures above the critical point—steam conditions with a pressure above approximately 3,200 psi and temperatures around 1,050°F. These technologies operate on the same basic principles to produce electricity, the difference being that supercritical units have steam conditions with higher operating temperatures and pressures, resulting in higher overall generating efficiency when compared to subcritical technology.

Recent advances in electrical generating unit technology have led to the creation of a new subset of the supercritical category, known as "ultra-supercritical" technology. The U.S. Department of Energy (DOE) has defined the ultra-supercritical steam cycle as a steam cycle with an operating pressure exceeding 3,600 psi and main superheat steam temperature approaching 1,100°F (DOE, 2005, p. 6).

Process Description

In a pulverized coal-fueled generating plant, coal is milled to a fine powder and blown into the boiler with hot air. The coal burns in suspension within the boiler. Low nitrogen oxides (NO_X) burners are used to reduce nitrogen oxide emissions and air-fuel ratios are used to reduce carbon monoxide (CO) emissions. Water is circulated through tubes lining the boiler and is turned into steam, which is used to propel a turbine-generator to produce electricity.

History

Pulverized coal-fired boiler technology is the primary means for generating power from coal with approximately 970,000 MW of capacity in operation worldwide and over 310,000 MW in the U.S. The majority of PC units in the U.S. are subcritical units built 25 to 50 years ago with steam pressures up to 2,400 psi and temperatures up to 1,050°F. Over 160 supercritical units were built in the U.S. from the 1960s to the early 1990s. However, many of these units had availability and operational problems. Because of these problems, supercritical technology fell out of favor in the U.S. Eventually, increased experience with the technology led to solutions, and numerous additional supercritical units have been built internationally. Today, both subcritical and supercritical PC technology are being constructed and operated in the U.S.

Advancements in metallurgy continue which allow higher temperature and pressure conditions and in turn increase the efficiency in the boiler. Overseas, some PC units have

been designed to operate at ultra-supercritical conditions exceeding 1,100°F and 3,600 psi. Ultra-supercritical units are being considered for new plants in the U.S. but would be operated below the more extreme steam conditions that may be found overseas.

Performance

Efficiency

Overall efficiency of power plant is expressed as percent efficiency, referring to the percentage of thermal energy in the coal that is converted to electrical energy, or by using the term heat rate, which measures the amount thermal energy required for the generation of one net kilowatt-hour (kwh) of electricity. In the U.S., the British Thermal Unit (Btu) is the unit of measure for thermal energy, and heat rates are typically stated as Btu/kwh. The efficiency of the unit increases with a higher the percent efficiency and a lower the heat rate.

The overall efficiency of a pulverized coal facility is affected by many factors, including, but not limited to, the steam conditions (for example, subcritical, supercritical), cooling system, parasitic load for auxiliary equipment (for example, emission controls, coal handling, etc.), and characteristics of the coal being used. Older subcritical units in the U.S. typically have efficiencies of 31 to 34 percent. Generally, current subcritical and supercritical designs with full environmental controls are expected to yield efficiencies in the range of 35 percent and 40 percent, with supercritical units at the upper end of range. Ultrasupercritical plants may be able to achieve efficiencies in the low 40 percent range.

The difference in efficiency between the various types of pulverized coal-fired generation varies based on the specific steam conditions used and the coal selected. Generally, the difference in efficiencies between subcritical and supercritical technologies may be between 1 percent and 3 percent. Similarly, the difference in efficiencies between supercritical and ultra-supercritical technologies may also be between 1 percent and 3 percent. The difference between modern supercritical plants and the ultrasupercritical plants being considered in the U.S. is thought to be approximately 1 percent.

Availability

Out of all of the coal-fired generating technologies, PC technology is the most proven and reliable. Unit availability is calculated by taking the number of hours in a year that the unit was available to produce power, dividing by the total number of hours in the year (8,760), and then multiplying by 100 percent. Unit availability levels exceeding 90 percent can be achieved today with the mature subcritical and supercritical technologies.

Fuel Source

PC technologies can be designed to burn various coal types including sub-bituminous, bituminous and lignite. PC technology has the flexibility to blend in a certain level of alternative types of solid fuel (for example, petcoke). However, once designed a PC unit generally operates using its design fuel in order to maximize output and efficiency and to minimize maintenance.

Operational Flexibility

PC-fired generation has proven operating flexibility to operate as baseload, load-following, and on-off cycling units. Minimum load for a PC-fired unit is in the range of 25 percent to 30 percent, without supplemental fuel.

Emissions

Emissions from PC technologies can be greatly reduced through the use of combustion practices and design (for example, low NO_X burners, overfire air) and post-combustion emission control equipment. Post-combustion emission controls include scrubbers for the control of sulfur dioxide (SO_2), selective catalytic reduction (SCR) for the control of NO_X, activated carbon injection for the control of mercury, and fabric filters (or a "baghouse") for the control of particulates.

The emissions from subcritical and supercritical designs are identical on a heat input basis (that is, pounds of emissions per million Btu of heat input). However, the overall emissions from a supercritical facility should be slightly less than a subcritical facility when producing the same amount of electric power, given the higher electrical generating efficiency of the supercritical design.

Cost

PC-fired generation is the most economic source of coal-fired generation, with firm pricing and performance guarantees available from multiple equipment vendors. There are cost advantages and disadvantages for using a supercritical design versus a subcritical design. The initial cost of a facility using a supercritical design is higher than a facility using a subcritical design. However, the ongoing cost of operations for a supercritical facility should be lower given the higher efficiency (that is, less fuel necessary to produce the same amount of electricity). Less information is currently available on the cost increases to use ultra-supercritical technology; however, it is generally accepted that capital costs for ultrasupercritical boilers are higher given that the technology relies on advanced materials to operate at the higher temperatures and pressures and there are fewer equipment suppliers for these boilers.

Commercial Use

Subcritical and supercritical PC boiler technologies are mature technologies, with the majority of coal-fired generation capacity in operation utilizing subcritical technology and more than 500 plants worldwide utilizing supercritical technology. Ultra-supercritical technology has very limited experience in the United States. In fact, a U.S. EPA report referring to ultrasupercritical technology with steam conditions of 4,500 psig and 1,100°F states that "[t]herefore, for application in this country, the technology is considered unproven with potential technical and economic risks" (EPA, 2006, p. ES-2).

Conclusion

Pulverized coal generation technology offers proven, reliable, and efficient operations. Low emission rates can be achieved through the use of pulverized coal technology with

advanced post-combustion technologies. Further, pulverized coal technology is the most economic method of coal-fired generation.

The Proposed Action is to use supercritical PC boiler technology. Subcritical PC technology does offer the potential for lower capital cost and has been considered as an alternative, but has been eliminated from detailed analysis because it does not offer any apparent environmental advantages, and the higher efficiency of a supercritical PC plant will at minimum offset a part of the higher cost through fuel savings.

Ultrasupercritical PC technology is a subset of supercritical PC boiler technology and as such the analysis conducted for supercritical technology envelopes the impacts of both technologies. The higher efficiency of ultrasupercritical PC technology does offer the potential for environmental advantages through less coal burned on per megawatt-hr basis, which in turn would slightly lower overall air emissions and solid waste on a pounds per megawatt-hour basis. Ultrasupercritical technology does represent a higher capital cost and represents greater operational risks because it has virtually no operating history in the U.S.

Circulating Fluidized Bed Combustion

Circulating fluidized bed is a power generation technology that combusts solid fuel held in suspension in a bed primarily consisting of fuel, fuel ash, limestone, and other inert materials. Circulating fluidized bed boiler technology has been successfully applied to the process industries and the electric power industry, although its application is limited by the smaller steam generating capacity that can be produced by a single circulating fluidized bed boiler (300 MW per circulating fluidized boiler). Without add-on controls, a circulating fluidized boiler can produce less NO_X and SO_2 emissions than an uncontrolled PC boiler; however, to achieve the currently required emissions levels, both circulating fluidized boilers and PC boilers must be equipped with add-on controls, thus removing the emissions advantage of circulating fluidized boilers. The circulating fluidized boiler continues to hold an advantage over the PC boiler with respect to its ability to burn a wider variety of coals and is well suited for waste coal.

Process Description

A circulating fluidized boiler combusts fuel in a bed of material consisting of fuel, fuel ash, limestone, and other inert bed materials. The bed is supported within the furnace by air flowing into the bed from the bottom of the furnace. The air flow supports the bed and promotes mixing of the fuel and air to provide complete combustion. The bed temperature is typically below 2,000°F, which maintains the fuel ash below the softening point and also reduces the formation of thermal NO_X. The bed is sized to achieve low gas velocities that allow for long fuel residence time in the furnace which helps complete combustion and maximize heat transfer to the water-cooled furnace walls. Simultaneous with the fuel combustion, limestone reacts with SO_2 formed during combustion to lower overall SO_2 emissions from the boiler.

The thorough mixing of air and fuel, low combustion temperature, long residence time, and in-situ removal of SO_2 make circulating fluidized technology an ideal system for the combustion of fuels with low volatile matter content (such as anthracite coals and petcoke), high ash content (such as waste coal), and high sulfur content. Additionally, a circulating fluidized boiler has greater fuel flexibility relative to a PC boiler, which gives an owner the ability to minimize fuel expenses by burning lower quality, lower cost fuels.

History

Fluidized bed technology development was initiated in the 1920s as a process for refining petroleum and producing chemical feedstocks from coal. Until the 1960s, fluidized bed technology was focused on the process industries. In the 1960s, governments (particularly in the U.S. and England) began looking at fluidized bed technology as a means to use coal while reducing emissions of SO_2 and NO_X. At that time, governments and boiler manufacturers began investing in the development of the technology and began building test modules and small scale commercial boilers. With the progression of time, a greater

understanding of the circulating fluidized technology was gained, which enabled boiler manufacturers to offer larger circulating fluidized boilers and expand the potential range of application from small industrial boilers to larger utility boilers.

The circulating fluidized combustion process is now a mature technology, and circulating fluidized boilers have gained acceptance as a steam generator technology for power generation. Table 1 summarizes some of the most recent domestic applications of circulating fluidized boilers for power generation.

TABLE 1
Domestic Circulating Fluidized Bed Boiler Applications for Power Generation

Plant	Location	Operation	Capacity MW (gross)	Fuel
Tractebel Red Hills	Mississippi	2001	2 x 250 MW	Lignite
JEA Northside	Florida	2001	2 x 300 MW	Coal, petcoke
AES Puerto Rico	Puerto Rico	2002	2 x 250 MW	Coal
Reliant Seward	Pennsylvania	2004	2 x 292 MW	Waste coal
East Kentucky Power Coop	Kentucky	2004	1 x 268 MW	Coal

Performance

Efficiency

The overall efficiency of a facility with a circulating fluidized bed boiler with advanced emission controls would be lower relative to a facility with a PC boiler with advanced emission controls because of lower combustion temperatures, smaller unit size, and higher power requirements of the circulating fluidized boiler auxiliaries. The efficiency of a circulating fluidized is several percent lower than a PC unit. The result of this lower efficiency is a higher fuel consumption rate for an equivalent electric generating capacity.

Availability

A limited amount of data is available for circulating fluidized bed units because of the fewer number of operating units and that most of the facilities are not required to report this information. However, circulating fluidized bed units are generally thought to have availabilities approaching 90 percent.

Fuel Source

The advantage of a circulating fluidized bed boiler is its ability to consume low cost "advantage" fuels not typically used in a PC boiler. These fuels are characterized by a high ash or moisture content, low heating value, and low volatile content and thus are lower cost on a $/MMBtu basis at the fuel source. Additionally, circulating fluidized bed boilers are able to burn biomass as a fuel source, making the attractive in areas that have large amounts of biomass available for a renewable fuel source. Transportation cost is a critical

consideration in determining the fuel source and, in the case of using lower value fuels, transportation distances exceeding 50 to 100 miles often removes any economic benefit of burning the lower value fuel relative to high quality subbituminous or bituminous coal. Long-term availability of these lower value fuels is also a consideration since a facility's economics will be severely impacted if the fuel source is no longer available in future years and higher cost fuels must be substituted. Therefore, most facilities equipped with a circulating fluidized bed boiler are located near one or more potential fuel sources to maximize the economic benefit of using the low value fuel and reduce the risk of fuel becoming unavailable.

Operational Flexibility

Circulating fluidized bed boilers have a more restrictive ramp rate than PC boilers because of the considerable mass of material in the bed that needs to be moved and kept within temperature ranges. Circulating fluidized bed boilers can operate at baseload and in a load-following mode. The load-following capability is limited in comparison to PC boilers. Minimum load for a circulating fluidized bed boiler is in range of 40 percent, without supplemental fuel (compared to the minimum load for a PC boiler in the range of 25 percent). Circulating fluidized bed technology is not well suited for on-off cycling. The bed material is susceptible to hardening if the bed temperature falls below its recommended operating range (Sargent & Lundy, 2005).

Emissions

The main advantage of a circulating fluidized bed boiler would be the lower emissions of NO_X and SO_2 relative to a PC boiler not equipped with selective catalytic reduction (SCR) or flue gas desulfurization (FGD). The lower combustion temperature of a circulating fluidized bed boiler would generate less thermal NO_X, while SO_2 emissions would be reduced by the reaction with limestone in the bed.

Recent facilities equipped with circulating fluidized bed boilers have used post-combustion controls to further reduce emissions of NO_X and SO_2 to meet the increasingly stringent emissions requirements. The controls typically applied are selective noncatalytic reduction systems (SNCR) to reduce NO_X emissions and dry FGD systems to reduce SO_2 emissions. An SNCR reduces NO_X by injecting urea or ammonia into the furnace which reacts with NO_X to form nitrogen (N_2), oxygen (O_2), and water. A dry FGD system may use bed material collected in a baghouse as the reagent or fresh lime feed similar to a dry FGD system installed with a PC boiler. The use of bed material or lime as the reagent in the dry FGD system is an economic decision based on the amount of additional SO_2 reduction required and the relative costs of limestone and lime.

Similar to recent circulating fluidized bed boiler installations, a new PC boiler would be required to install post-combustion controls to reduce emissions of NO_X and SO_2. The systems typically installed are SCR for control of NO_X emissions and FGD for control of SO_2 emissions. The addition of these systems enables a PC boiler facility to have emissions equal to the emissions from a facility equipped with a circulating fluidized bed boiler, SNCR, and dry FGD system. However, a facility equipped with a circulating fluidized bed boiler will have a lower overall efficiency than a comparably sized facility equipped with a PC boiler because of greater auxiliary power requirements of the circulating fluidized bed boiler

facility. Therefore, more fuel will have to be burned to produce the same amount of electricity, likely leading to greater total annual emissions at a circulating fluidized bed facility than a PC plant.

The amount of combustion products generated by a facility equipped with a circulating fluidized bed boiler and a dry flue gas desulfurization (FGD) system would be higher than a facility equipped with a PC boiler and a dry FGD system as a result of the overall lower efficiency of the CFB boiler based facility and the higher limestone consumption of a CFB boiler relative to the lime consumption of a PC boiler equipped with a dry FGD system. Table 2 shows a comparison of the fuel and reagents consumed by each technology and byproducts generated for a 600-MW facility firing PRB coals. A 600-MW plant is used since that would maximize the efficiency for CFB boilers (two 300-MW circulating fluidized bed units).

TABLE 2
Comparison of Fuel Consumption and Solid Waste Generation for a 600-MW Plant

Throughput	Two CFB Boilers (tpy)	PC Boiler (tpy)
Fuel consumption	3,222,749	3,154,383
Incremental fuel consumption	68,366	--
Fuel ash	165,971	159,699
Sulfur absorption products	117,849	64,375
Incremental disposal volume	53,474	--

Cost

Five or six circulating fluidized bed units would be needed in order to generate the steam flows required to generate 1,600 MW, which is the maximum proposed capacity for the proposed action. The use of additional boilers to achieve a given steam flow is more costly because of the increased physical size of the facility, the incremental ancillary equipment to support additional boilers (for example, conveyors, control systems), and the incremental staff to operate and maintain the additional boilers.

Commercial Use

Circulating fluidized bed boiler technology is a mature technology that is commercially available from multiple suppliers. Application of a circulating fluidized bed boiler is principally driven by the fuel to be consumed. A single circulating fluidized bed boiler is currently limited in capacity to approximately 300 MW; greater capacities would require multiple boilers. In contrast, a single PC boiler can be furnished with a capacity up to approximately 1,000 MW.

Conclusion

Circulating fluidized bed boiler technology is alternative considered but not carried forward for detailed analysis in the EIS because it does not offer any apparent environmental or economic advantages over the proposed action as summarized below:

- Five or six CFB units would be required versus the two or three supercritical pulverized coal units. This would cause an increase in the project's footprint and increase capital and operational costs because of loss of economy-of-scale.
- No reliable local fuel sources are available that could be used to realize the advantage of the CFB boiler technology.
- On a heat input basis (lb/MMBtu), most emissions would be similar to the proposed supercritical pulverized-coal power plant; however the CFB technology has lower overall efficiency, which would cause it to generate more emissions on a pounds per hour basis.
- A 1,600-MW CFB plant would consume approximately 181,000 tons per year of additional coal, increasing air emissions and coal deliveries as compared to the proposed action.
- A 1,600-MW CFB plant would create approximately 142,000 tons per year of additional solid waste for disposal as compared to the proposed action.

Integrated Gasification Combined Cycle

Integrated Gasification Combined Cycle (IGCC) is an evolving power generation technology relying on gas turbine technology to produce electricity and offering the potential for improved environmental performance and high efficiency. IGCC is a two-step power generation method that produces synthesis gas (syngas) through the gasification of a solid or liquid feedstock (for example, coal, petcoke, or heavy oil), and also uses the syngas to power a combined cycle power block (combustion turbine in combination with a heat recovery steam generator and steam turbine). Emission controls are generally installed pre-combustion in an IGCC facility as compared to PC and CFB coal-fired generation technologies, where emission controls are generally installed post-combustion.

IGCC technology is a combination of processes from the petrochemical industry (gasification to generate syngas) and the power industry (gas-fired combined cycle power generation). In the petrochemical industry, gasification is used worldwide to produce a variety of products. In the power generation industry, however, the application of the gasification process to supply syngas to combustion turbines is limited to a very small number of plants operating in the U.S. and other parts of the world. Facility sizes for these installations range in size from 40 MW to 320 MW.

Currently, carbon capture and sequestration (CCS) technology has not been demonstrated in practice for a coal-fueled IGCC unit (Katzer et al., 2007, p. xiii). Thus, the viability of CCS technology in conjunction with IGCC for power generation has not been proven. Consequently, the discussions in the following text focus on IGCC without carbon capture, a technology that has been demonstrated in practice. A detailed discussion of CCS technology with respect to IGCC is provided in the section *Carbon Capture and Sequestration for IGCC Units*.

Process Description

There are actually four separate primary processes in an IGCC power plant, only one of which produces electricity: gasification, syngas cleanup, cryogenic air separation, and combined cycle power generation. Three of the four required processes are foreign to the conventional power generation industry and are typically classified as belonging to the chemical industry.

Gasifiers

Gasification is the process of converting a liquid or solid feedstock in a gasifier to a gas mixture (referred to as syngas) primarily composed of hydrogen and carbon monoxide. Gasifiers are generally classified into one of three categories: moving-bed reactor, fluidized-bed reactor, and entrained-flow reactor. Each of the technologies converts a carbon based feedstock in the presence of oxygen and steam while at high pressure and temperature into raw syngas which is primarily composed of hydrogen and carbon monoxide. The raw syngas also contains carbon dioxide, moisture, hydrogen sulfide, carbonyl sulfide, methane,

ammonia, hydrogen chloride, and trace amounts of other components present in the feedstock.

In a moving-bed reactor, large particles of coal move slowly down through the gasifier while reacting with gases moving up through it. This counterflow pattern creates several different reaction zones that accomplish the gasification process at temperatures averaging 1,470°F to 1,830°F.

Fluidized-bed reactors continuously feed coal into a 1,470°F to 1,650°F reactor so that coal at all stages of the reaction process is in the same reaction zone. Steam and oxygen/air are fed from the bottom and rise up through the bed of coal.

Entrained-flow reactors mix a stream of fine coal particles with steam and oxygen/air at high temperatures of 2,730°F to 3,450°F to create a stream of tar and oil free crude gas.

In theory, each gasifier configuration can be designed to use either air or oxygen to react with the coal for syngas production; however, only oxygen-blown systems have currently been proven at commercial scale. Air blown systems have been attempted but not successfully scaled up to commercial size as evidenced by experience at the air-blown fluidized bed KRW gasifier at the Piñon Pine IGCC facility near Reno, Nevada. This unit was converted to operation as a conventional natural gas-fired generating plant in the mid 1990s after it failed to reach steady state IGCC operation.

Syngas Cleanup

After gasification, some levels of impurities, depending on the removal technology chosen, such as sulfur compounds, metals, alkalytes, ash, and ammonia are removed from the syngas in the gas clean-up process to reduce the ultimate level of emissions and prevent corrosion of the combustion turbine.

The syngas typically exits the gasifier at high temperature and must be cleaned of pollutants and other constituents that can cause corrosion and/or erosion to downstream equipment. Currently available technologies for syngas cleanup require the gas to be cooled to approximately 400°F so that the majority of the hydrogen sulfide and other byproducts can be removed. However, cooling of the syngas for cleanup results in an efficiency loss in the system; therefore, it is preferable to be able to clean the syngas at the gasifier exit temperature. Systems have been proposed for syngas cleanup at higher temperatures (1,000°F to 1,250°F), but those systems have not yet been commercially successful. Research continues into the development of an operable hot gas cleanup system.

Cryogenic Air Separation

The cryogenic air separation process provides the oxygen necessary for the gasification process and can be integrated with the combined cycle power block to provide nitrogen gas to the gas turbines to reduce NO_X emissions. Current gasification processes require a compressed oxygen feed to the gasifier, which is generated by an air separation unit. Compressed oxygen generation is well proven and used extensively worldwide; however, the process is very expensive and energy intensive.

Combustion Turbine Combined Cycle

After the three chemical processes are completed, the cleaned syngas is supplied to a gas combustion turbine for use in a combined cycle power block. Because of the lower heat content of syngas relative to natural gas, the mass flow through the combustion turbine needs to be much higher with syngas, thereby affecting the ease at which some combustion turbines can be converted to syngas use. Nitrogen from the air separation unit or steam can be injected into the combustion turbine to reduce the flame temperature and reduce the NO_X emissions.

History

While gasification technology has existed since the 1870s and was used extensively by Germany, France, and Britain during World War II to create fuel, the integration of the chemical gasification process equipment with a gas-fired combined cycle power block for electricity production is a more recent and still-developing technology. In general, there have been two generations of IGCC power plants built; the first generation in the mid-1980s, and the second generation in the mid-1990s. Both generations have relied heavily upon government funding and financing, and neither have been scaled up larger than 321 MW in size.

Table 3 summarizes the IGCC coal-fired power plants built to date which use oxygen-blown, pressurized entrained flow gasification. Note that none have exclusively used Powder River Basin (subbituminous) coal.

TABLE 3
Coal-Fired IGCC Power Plant Summary

Plant	Location	Operation	Power MW (net)	Design Feedstock	ASU-CT Integration	Financial Support
SCE Cool Water	Barstow, California	1984-1988	120	Bituminous Coal	None	EPRI and Utility Consortium
LGTI (Destec/Dow)	Plaquemine, Louisiana	1987-1995	160	Subbituminous Coal natural gas blend (80/20)	None	Partial DOE
NUON (Demkolec B.V.)	Buggenum, The Netherlands	1994 – present	254	Bituminous coal	100%	Netherlands government support
Global Energy – PSI Wabash River (Destec)	Terre Haute, Indiana	1996 – present	262	Bituminous Coal (now 100% petcoke)	None	Partial DOE
TECO Polk Power Station	Polk, Florida	1996 – present	260	Bituminous Coal and Petcoke	None	Partial DOE
Frontier Oil & Refining Co.	El Dorado, Kansas	1996 – present	40 (cogen)	Petcoke	<25%	State tax-exempt bonds for use of petcoke
Elcogas S.A.	Puetollano, Spain	1997 – present	321	Coal and petcoke	100%	Spanish government support
Motiva Enterprises Refinery	Delaware City, Delaware	2000 – present	180	Petcoke	N.A.	State tax-exempt bonds for use of petcoke

While several of the plants were originally designed to operate on coal, of the six IGCC plants presently operating, only one operates exclusively on coal, while the rest fire either a combination of petcoke and coal or 100 percent petcoke. In a report for Illinois on the possibility of using IGCC at the Prairie State Generating Station, SFA Pacific noted that switching to petcoke improved the availability of the Wabash River facility (the facility was able to run more reliably and often using petcoke) (SFA Pacific, 2003). The gasification of petcoke is not directly comparable to gasification of coal because petcoke is a byproduct of refining processes and has characteristics different than coal. To date most gasification of coal has centered on bituminous coals, and only limited research has been conducted on the gasification of lower rank coals, such as subbituminous Powder River Basin coal. Without additional research or commercial experience, it is difficult to compare the gasification technology development with low rank coals to that of bituminous coal (EPA, 2006).

Currently there are six IGCC technology owners. These technology owners typically license the technology to third parties who would be responsible for the detailed design and erection of an IGCC electric generation facility. While two of the owners have partnered with construction firms with the intent of providing turnkey IGCC facilities, neither consortium has yet provided firm cost and performance guarantees for an IGCC power generating facility.[1] Firm pricing and performance guarantees are critical for making a project commercially viable. Without firm pricing, neither the project owner nor the lending institution(s) would have any assurance that the amount financed would be sufficient to complete construction of the facility and allow the owner to satisfy its loan payment obligations. As a result, any cost overruns would need to be passed on to electric customers, which would present a similar issue for the customers as they would not want to be responsible for substantial price increases. Similarly, without performance guarantees, neither the project owner nor the lending institution(s) would have any assurance that the proposed IGCC facility could meet its obligations to supply reliable baseload power. The financial penalties that could result from unreliable IGCC performance (for example, availability penalties under power contracts or lost revenue because of generation outages) could jeopardize the proponent's ability to satisfy its loan payment obligations. In addition, if the environmental performance requirements are not met (for example, efficiency is not met or emissions are higher) the project would be subject to environmental fines and could face potential shutdown of operations. Because of these financial risks, along with the technical risks to be discussed in subsections below, units representing this next generation of IGCC technology have not been financed, constructed, and operated successfully. As such, the cost, actual efficiency, availability, and environmental performance of the next generation of IGCC plants remain uncertain.

Table 4 lists the current IGCC projects that have been recently permitted in the U.S. It is acknowledged that a number of additional IGCC projects are in various stages of development in a number of different states across the U.S.

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[1] For example, in recent testimony before the Virginia State Corporation Commission, Appalachian Power Company asserted with regards to its proposed IGCC plant in West Virginia "that GE/Bechtel are willing to *consider* guarantees of the performance of this [IGCC] plant *after* it begins operation." [original italics] (See Commonwealth of Virginia State Corporation Commission, Final Order, Case No. PUE-2007-00068, April 14, 2008.)

TABLE 4
IGCC Projects Permitted

Plant	Location	Net Power (MW)	Primary Fuel	Permit Status	Construction Status	Financial Support
Kentucky Pioneer	Kentucky	580	Unknown	Permit expired June 2006	IGCC Project Suspended by Developer	DOE Grant of $78 million [a]
Lima Energy	Ohio	540	Petcoke	Permit issued March 2002	Pending Financing [b]	--
Elm Road	Wisconsin	600	Bituminous coal	Permit issued January 2004	IGCC Project Denied by Wisconsin PSC	--
Stanton	Florida	285	PRB	Permit issued December 2006	Cancelled November 2007	DOE Grant of $235 million
Taylorville Energy Center	Illinois	630	Bituminous coal	Permit issued June 2007	Not started	Cost Recovery Guarantee [c]
Duke Energy	Indiana	630	Indiana coal	Permit issued November 2007	Construction uncertain pending air permit appeals process	--

[a] Global Energy, 2007
[b] Global Energy, 2007
[c] Blankinship, 2007

Table 5 lists the project summary of the IGCC projects that have been announced to date. Of the 20 projects shown in Table 5, the following can be said:

- Permitted = 6
- Canceled = 8
- On hold = 7
- Construction = 0
- That have incorporated carbon capture = 4 (all of which have been postponed or cancelled)
- Proposed at elevations less than 4,000 feet amsl = 17
- Proposed at elevations above 4,000 feet amsl = 3 (all of which have been postponed or cancelled)
- Proposed IGCC plant capacities are average 597 MW, with a maximum of 1,100 MW and a minimum of 275 MW.

Performance

A potential advantage of IGCC is that IGCC technology theoretically has superior thermal efficiency and environmental performance over other coal technologies. Concerns with IGCC include the maturity of the technology for commercial use, the reliability, the cost, and whether the efficiency and environmental performance can actually be achieved.

TABLE 5
IGCC Project Summary

IGCC Facility	Capacity (MW)	Fuel	Regulatory & Financial Incentives	Carbon Capture?	Approx. Site Elevation (ft amsl)	Status/Date Cancelled
Duke – Edwardsport, Indiana	630	Indiana coal	Total $460M federal, state, and local incentives including $133.5M DOE tax credit. Granted guaranteed cost recovery by the Indiana Utility Regulatory Commission for all construction, operating, and maintenance costs.	No	500	Under development. Air permit under appeal by Sierra Club and others. Construction uncertain pending air permit appeals process.
AEP – Great Bend, Meigs County, Ohio	629	Primary: Northern Appalachian coal Secondary: petcoke, natural gas	Rate recovery of $23.7M in pre-construction costs granted. AEP requiring regulated rate of return for project with cost recovery assurances in order to construct.	No	600	On hold because of March 2008 deregulation decision by Ohio Supreme Court. Uncertain if project will be allowed to obtain cost recovery for construction.
Tenaska – Taylorville Energy Center, Taylorville, Illinois	630	Illinois coal	$5M from state of Illinois, $500M in tax exempt bonds. Project requires new state legislation to require utilities to enter into long-term contracts purchasing power from the project.	No	600	Under development. Has not received long-term power purchase agreements. Air permit under appeal by Sierra Club.
Pacificorp – Jim Bridger, Wyoming	500	Coal	Severance tax exemptions on coal	Not specified	6,600	Cancelled November 2007.
Tampa Electric – Polk Unit 6, Polk County, Florida	630	Coal-bituminous	$133.5M DOE tax credit	No	100	Cancelled October 2007.
Southern Co. & Orlando Utilities Commission – Stanton Energy Center, Orlando, Florida	285	Coal - PRB	$235M DOE funding	No	100	Cancelled November 2007.
FutureGen Alliance – Mattoon, Illinois	275	Coal	$1,100M DOE funding prior to program restructuring. DOE has withdrawn financial support for the Mattoon site as part of project restructuring.	Yes	700	Status uncertain because of rising costs. DOE restructured the program in January 2008 to fund only the CCS portion of multiple IGCC plants in the future.

TABLE 5
IGCC Project Summary

IGCC Facility	Capacity (MW)	Fuel	Regulatory & Financial Incentives	Carbon Capture?	Approx. Site Elevation (ft amsl)	Status/Date Cancelled
Xcel Energy – Colorado	600	Coal	$3M per year to study IGCC in Colorado per HB 1281	Yes	4,200	Postponed October 2007. High cost, unable to find partners.
Cash Creek Generation, LLC (Erora Group) – Henderson County, Kentucky	630	Kentucky mine-mouth coal	grant from the KEDFA and the Commerce Cabinet for the office of Energy Policy for $303,000	No	500	Under development. Final air permit issued 01/17/08. Air permit under appeal.
WE Energy – Elm Road Generating Station, Wisconsin	615	Northern Appalachian Coal	Not specified	Not specified	700	Cancelled November 2003.
Excelsior Energy – Mesaba, Taconite, Minnesota	600	PRB Coal	$36M DOE grant, $800M federal loan guarantees, $12M in bond financing to Itasca County, $10M loan for start-up costs from Iron Range Resources, $10M grant from PUC, 2003 state law requiring Xcel to purchase 450 MW	No	1,400	On hold. Unable to obtain purchase agreements.
Energy Northwest – Pacific Mountain Energy Center, Washington	600	Coal or petroleum coke	Not specified	No	1,500	Cancelled December 2007.
United Power Company, Quigg Energy Group, LLC, and Washington and Sunwest Management, Inc. – Wallula Energy Resource Center, Walla Walla County, Washington	700	Coal	Not specified	Yes – approx. 65% capture	1,000	On hold. IGCC plant was contingent on results of a carbon storage pilot project. Pilot project was postponed indefinitely in March 2008.
Tondu – Nueces, Texas	600	Originally petcoke and coal. Now natural gas.	Not specified	Not specified	16	IGCC plans cancelled. Switched to natural gas in June 2007 because of high cost.

TABLE 5
IGCC Project Summary

IGCC Facility	Capacity (MW)	Fuel	Regulatory & Financial Incentives	Carbon Capture?	Approx. Site Elevation (ft amsl)	Status/Date Cancelled
Bowie Power - Arizona	600	Coal	Applied for DOE funding	Yes – Up to 4% capture in plants	3,800	Cancelled IGCC September 2007. Development started as Natural 1,000-MW gas. Switched to 600-MW IGCC in 2006. Switched back to natural gas in 2007. Market economics, regulatory uncertainty stated as reasons.
AEP – Mountaineer, New Haven, West Virginia	629	Coal	$133.5M in tax credits, project is contingent on obtaining guaranteed cost recovery	No	600	Permitting stage. Draft air permit as early as April 2008.
Global Energy, Inc. – Lima Ohio	540	Petcoke	Not specified	No	900	Permitted. Began construction in October 2005. Delayed pending financing
AEP/Madison Power – Southern Illinois Clean Energy Center, Illinois	Approx. 600	Illinois coal	$5 million in funding from the State of Illinois for the engineering and design study. $2.5 million grant by the Illinois Clean Coal Review Board for the initial phase of detailed engineering design	No	400	Not specified. No developments since 2006.
Buffalo Energy Partners – Converse County, Wyoming	1,100	Western coal	Not specified	Not specified	5,700	Cancelled October 2007.
Global Energy – Kentucky Pioneer, Kentucky	540	Co-feed of coal and refuse derived fuel	Cost-shared with DOE under Clean Coal Technology Program. DOE to provide $60 million in Federal funding support (about 15% of the total cost of approx. $414 million) to design, construct, and demonstrate the commercial scale operation of the technology.	Not specified	800	Permitted, not constructed. In 2006, project suspended and no longer considered probable in near term.

Efficiency

One stated goal for the IGCC technology is to achieve overall efficiency levels of 45 to 50 percent by 2010 and 50 to 60 percent by 2020 (Morehead, et al., 2004). These high efficiencies have not yet been achieved in practice by the four operating IGCC facilities as actual efficiencies have ranged from the mid-thirty to forty percent. These efficiencies can and are being achieved by recently built PC facilities. For example, Table 6 shows the actual historical heat rates for the Polk Power Station IGCC facility during the last 10 years (note: the lower the heat rate, the more efficient a plant is), which calculate to efficiencies between 31.2 percent and 35.9 percent. Many existing PC plants are achieving these efficiencies in the range of 31.2 percent to 35.9 percent, and this efficiency range would be surpassed by a modern supercritical PC plant. The use of combustion turbines at high elevations, such as the Proposed Action, results in a lower the net output because of the lower density of air.

TABLE 6
Polk Power Station Historical Heat Rate

	Polk Power Station*									
Year	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Heat Rate (Btu/kWh)	10,523	10,909	10,950	9,495	9,775	9,633	9,674	9,815	9,934	10,146

* EPA, 2008

Availability

In an article in October 2006, *Power* magazine reported that the availability histories of the six successful IGCC demonstration projects show that most were able to reach the 70 percent to 80 percent availability range but only after at least 5 years of operation (Javetski, 2006). In comparison, PC-fired generation has been shown to have an expected minimum availability of 90 percent generally achievable within the first year of commercial operation. Table 7 shows the IGCC equivalent availability for the Nuon, Wabash, Polk, and Elogas plants which show that all had availabilities 60 percent and below during the first 3 years of operation, and only one has managed to obtain 80 percent after 7 years of operations.

Although not an IGCC power plant facility as it does not generate electricity, the Eastman Kodak Facility in Tennessee has been cited as a successful implementation of gasification technology because of its 2000 to 2003 reliability of 98.1 percent. It should be noted that this reliability figure does not include the power generation equipment that would be necessary for an IGCC power plant facility, is based on a facility equipped with a spare gasifier which adds significantly to the initial capital cost, and has been achieved in part because of having 20 years of operating experience with this facility (Trapp, 2004).

TABLE 7
IGCC Equivalent Availability*

Plant	Nuon	Global Energy (Wabash)	TECO (Polk)	Elogas
Gasifier	Shell	COP E-Gas	GE HTHR	Prenflo
Net Output	252 MW	262 MW	250 MW	300 MW
Years after Startup	IGCC Equivalent Availability (percent)			
1	23	20	35	16
2	29	43	67	38
3	50	60	60	59
4	60	40	75	62
5	61	70	69	66
6	60	69	74	58
7	57	75	68	NA
8	67	78	81	
9	73	-	82	
10	78	-		
11	NA			

Notes:

1. Data are based upon available information. Data reporting methodology varies somewhat between plants.
2. Wabash Years 5 to 8 IGCC equivalent availability estimated as 95% of reported syngas availability.
3. Wabash availability excludes periods when the plant was shut down because of no product demand (24% in Year 7 – 2002 and 16% in Year 8 – 2003, shutdown in Year 9 – 2004 and Year 10 – 2005).

* Black & Veatch, 2007

Fuel Source

No IGCC units exist which have currently or historically operated on 100 percent subbituminous PRB coal, which is the design fuel for the Proposed Action. Relatively little research or commercial work has been done to investigate gasification of the lower rank coals, including subbituminous and lignite, for electric generation purposes (EPA, 2006). This lack of experience is highlighted by the $235 million in government funding given to Southern Company to build a 285-MW PRB-fired IGCC demonstration unit in Orange County, Florida (this project was terminated two months after construction began because of regulatory uncertainties and will now be built as a natural-gas fired plant) (Orlando Utilities Commission, 2007). Furthermore, the Energy Policy Act of 2005 allows for funding to support an IGCC project using western coal. While vendors claim that PRB can be gasified, they also indicate that the fuel feed system and overall heat rate will be affected. GE, one of the IGCC technology owners, has stated that PRB coal is only ready for gasification in the short term if blended with petcoke (GE, 2005). This lack of IGCC experience with western coals is supported by American Electric Power (AEP), a company currently proposing to construct both IGCC and PC facilities. AEP has stated that "the IGCC technology developed by GE does not work well with western coals that have lower Btu

value and higher moisture content than eastern coals. Although competing gasification technology can use western coals, the owners of this technology are not yet providing performance guarantees necessary to make it a commercially viable option" (Rencheck, 2007).

Operational Flexibility

The operational flexibility of IGCC units is significantly less than that of PC-fired generation. PC-fired generation has proven operating flexibility to operate as baseload, load-following, and on-off cycling units. Minimum load for a PC-fired unit is in the range of 25 percent to 30 percent, without supplemental fuel. IGCC is best operated only as baseload. For a 2 x 2 configuration, with two combustion turbines and two gasifiers, some load following can be accomplished, either by load reducing on individual combustion turbines (range is 60 percent to 100 percent) or shutting down a gasifier/combustion turbine train. The gasifiers are best operated at a constant rate rather than cycled. The operating range of the gas turbine is typically 60 percent to 100 percent, with the heat rate deteriorating at lower loads (Sargent & Lundy, 2005).

The lower reliability of IGCC plants and the resulting increase in the number of annual starts, shutdowns, and malfunctions has the potential to consume additional energy from the grid and/or increase the total annual emissions emitted from the facility. Another operational disadvantage is that an IGCC facility firing syngas takes longer to start up than does a PC-fired unit (Sargent & Lundy, 2005).

Emissions

Emissions data is generally available for the existing generation of IGCC facilities in operation in the United States and the emission reductions have generally not exceeded what can be accomplished with a modern PC plant. While it may be possible to further reduce the pollutant emissions for the next generation of IGCC facilities through modifications to the control process or addition of specialized pollution control units, this would further add to the cost and complexity of an IGCC plant. Further, this next generation of IGCC facilities has yet to be constructed and, and as such, any lower emission levels have not been demonstrated and cannot be considered a reliable point of comparison to the mature and reliable PC-fired technology. A number of proposed IGCC projects are being permitted throughout the U.S. with varying emission rates proposed. However, none of these projects have been constructed, and emission rate guarantees by vendors are not readily available. Accordingly, the demonstrated performance of existing IGCC power plants serves as a comparison point for the Proposed Action, which is using mature technology for which vendor-guaranteed emission rates are available. Table 8 provides a comparison of the demonstrated performance of IGCC power plants versus the air emissions limits for the Proposed Action.

TABLE 8
Comparison of Demonstrated IGCC Emission Rates

	Facility Emissions (lb/MMBtu)			
Pollutant	TECO (Polk)	Global Energy (Wabash)	LGTI (Destec/Dow)	Proposed Action
SO_2	0.135-0.224[a,d]	0.132-0.266[a,d]	<0.15[g]	0.065-0.09[b]
NO_X	0.09-0.15[a,d]	0.14-0.17[a,d]	<0.26[g]	0.07[b]
PM_{10}	0.013[c,e]	0.012[f]	<0.01[g]	0.015[c]

Notes:
[a] Annual averaging period.
[b] 24-hour averaging period. For SO_2, 0.065 lb/MMBtu corresponds to lower sulfur coals (<0.45% S); 0.09 lb/MMBtu corresponds to higher sulfur coals (≥0.45% S).
[c] 3-hour averaging period.
[d] From U.S. EPA Acid Rain Program data.
[e] Represents air permit limits.
[f] Wabash River Energy, Ltd., "Wabash River Coal Gasification Repowering Project Final Technical Report," August, 2000.
[g] Brown, et al., "An Environmental Assessment of IGCC Power Systems," presented at the Nineteenth Annual Pittsburgh Coal Conference, September 23-27, 2002.

Cost

The cost of an IGCC facility is substantially higher than that of a PC or CFB coal-fired generation facility. AEP has filed for approval of both a 629-MW IGCC facility in West Virginia utilizing eastern bituminous coal and a 616-MW PC facility in Arkansas utilizing Powder River Basin coal. AEP has provided construction cost estimates, excluding carrying costs, of $2.23 billion ($3,545/kW) for the IGCC facility in West Virginia (Waldo, 2007) and $1.343 billion ($2,175/kW) for the PC facility in Arkansas. The capital cost of the IGCC facility is over 60 percent higher than the PC facility.

A recent report prepared by Black & Veatch for Florida Power & Light estimated the engineering, procurement, and construction (EPC) capital costs for an IGCC plant to be 22 to 39 percent higher than a PC facility, and approximately 15 percent higher than a CFB facility (Kobyia, 2006).

IGCC cost estimates are significantly affected by the type of fuel burned. PRB coal, because of the high moisture and lower heat content, would require larger or additional gasifiers to process sufficient fuel for the combustion turbines, and depending on the type of IGCC technology used, the coal might have to be dried prior to gasification, further increasing the costs. PRB coal also has a low fixed carbon ratio, increasing the difficulty of gasification. The low fixed carbon is the reason GE presently will only offer a PRB/petcoke blend gasification system; a 100 percent PRB system is not available.

Also relevant are decisions by regulatory agencies that IGCC technology is not cost effective. Recently, the Minnesota Public Utilities Commission has determined that the pricing provisions of the Mesaba IGCC project proposed in Minnesota "are likely to impose unreasonable and excessive costs on [the utility's] ratepayers" and "carry so many serious risks that the advantages of IGCC technology are not enough to counterbalance them, let alone to tip the scales in favor of contract approval." (Minnesota Public Utilities

Commission 2007). The Administrative Law Judge found that the "power would cost approximately 30 percent more than power from comparable facilities over the life of the contract" resulting in "unreasonably high prices for [the utility] and unreasonably high rates for [the utility's] ratepayers" (Minnesota Public Utilities Commission 2007). Previously, Wisconsin Energy submitted an application to the Wisconsin Public Service Commission to construct a new facility called Elm Road Generating Station (ERGS) consisting of two supercritical pulverized coal units and a single IGCC unit. The Wisconsin Public Service Commission approved both of the PC boilers but denied the IGCC unit. The DNR stated that IGCC was "a different type of process technology" from supercritical pulverized coal, and for this reason, IGCC should not be included in the BACT/LAER analysis for the ERGS (Wisconsin State Court Decision, 2005). Also, SFA Pacific, Inc. in its May 11, 2003 filing to the Illinois EPA, found that for the Prairie State Energy Campus, the costs of producing electricity using an IGCC plant would be 33 percent to 36 percent higher than for the proposed PC plant (SFA Pacific, 2003). The Illinois EPA supported that finding in its issuance of an air permit for construction of PC boilers at the Prairie State Energy Campus (Illinois Environmental Protection Agency, 2005). Finally, the Arizona Corporation Commission stated that "IGCC is not yet a mature, reliable or economic technology alternative for the SGS [Springerville Generating Station]" (Arizona Corporation Commission, 2005).

Commercial Use

IGCC technology has limited commercial experience and is considered a developing technology. IGCC plants currently proposed in the U.S. are seeking some combination of governmental funding and/or special ratemaking rules. In a report released in July 2006, the Environmental Protection Agency stated that development and implementation of the IGCC technology is relatively immature when compared with PC technology (EPA, 2006). IGCC plants are not readily available from equipment vendors with performance guarantees and price certainty. Currently, equipment vendors are requiring interested parties to fund front-end engineering and design studies to make the next generation of IGCC technology available. The studies are expected to aid in the evaluation of performance and cost for a new IGCC, however, proving out this data will require construction and operation of multiple IGCC plants over a multi-year period.

Actions taken by the United States Government reflect the risk associated with projects that employ new or developing technologies. To encourage the advancement and commercial use of gasification technology, Title XVII of the Energy Policy Act of 2005 provides incentives for new or significantly improved technologies as compared to commercial technologies in service in the United States, including IGCC. Subject to an appropriation for the cost, the Act enables the Secretary of Energy may make loan guarantees of up to 80 percent of the cost for an eligible facility if the facility is located in a Western State on a site with elevation greater than 4,000 feet (Title XVII of the Energy Policy Act of 2005, Public Law 109-58, August 8, 2005. 42 USC 16511—16513). Additionally, a facility receiving the loan would be required to meet certain technical requirements and must document an assured revenue stream covering capital and operating costs (including servicing all debt obligations covered by the guarantee). To date, no IGCC facilities have been constructed using these potentially-available funds, and currently, no publicly-announced and active IGCC development projects are seeking these funds.

While an IGCC facility located in White Pine County would meet the minimum elevation requirements for the loan guarantees, this does not imply nor assure the project would receive loan guarantees. In order to receive these incentives, there are other criteria that candidate projects are required to meet, including demonstration of operating on various coal supplies and, importantly, the requirement that the assured revenue stream cover capital and operating costs. The incentives provided for in the Act do not make IGCC a reasonable alternative for the White Pine Energy Station, because the project would still need to overcome the same obstacles as an IGCC project without these incentives to meet the purpose and need of the proposed action.

Conclusion

IGCC technology is alternative considered but not carried forward for detailed analysis in the EIS because it does not meet the purpose and need of the proposed action as summarized below:

- IGCC is still a developing technology. Current IGCC plants are small scale (300 MW or less) and were funded in part with government subsidies. New IGCC plants being proposed are being proposed at up to 600 MW in size, but larger plants are not being considered because of the uncertainties associated with the technology.
- Existing IGCC plants have not achieved the reliability needed for a large, baseload generation facility.
- Existing IGCC plants have efficiency values that are similar to or lower than modern PC plants.
- New IGCC plants are acknowledged to be substantially more expensive to construct, and represent significant commercial risks associated with actual performance (reliability, efficiency, and environmental).
- IGCC has not been proven capable to operate solely on PRB coal, and concerns with this remain on the new generation of IGCC. In addition, the location of the proposed action is not well-situated to other fuel supplies (that is, petcoke, natural gas, or large reserves of bituminous coal).
- If the gasifier at an IGCC plant located in White Pine County failed, there would be no back-up fuel supply to make the project useful since natural gas pipelines are approximately 100 miles from this area.
- Performance of an IGCC at a location in White Pine County would be hindered by the high elevations found in White Pine County, resulting in reduced power production capability of the combustion turbines.

Carbon Capture and Sequestration for IGCC Units

Future regulations on carbon dioxide (CO_2) emissions or other market incentives could potentially require U.S. power plants to capture and sequester emissions of CO_2. In the context of an IGCC unit, "capture" of CO_2 refers to the removal of CO_2 prior to combustion in the combustion turbine. CO_2 that is "sequestered" would be permanently stored in a manner that would prevent the CO_2 from reaching the atmosphere. The combination of carbon capture and sequestration is referred to as "CCS technology."

Carbon Capture

Although carbon capture technology has not been demonstrated in practice for a coal-fueled IGCC unit, (Katzer, James, et al., 2007, p. xiii). CCS technology has the potential to be incorporated into the IGCC process in the future. An IGCC unit equipped with carbon capture (that is, a unit where carbon dioxide, CO_2, is captured for storage and sequestration) would use a process different from that described previously. Applying CO_2 capture to an IGCC unit would require three additional sets of process units downstream of the gasifiers (Katzer, James et al., p. 34):

- Shift reactors
- CO_2 separation process
- CO_2 compression and drying

In the shift reactors, CO in the syngas produced by the gasifiers would be reacted with steam over a catalyst in the presence of heat to produce CO_2 and hydrogen at concentrations of 40 percent and 55 percent, respectively, in the resulting syngas stream (DOE, 2007, p. 18). Facilitated by the high CO_2 concentration and high temperature, CO_2 could be removed from the syngas stream by a variety of physical or chemical processes, such as glycol solvents or membrane separators (DOE, 2007, p. 18). After removal of CO_2 from the syngas, the gas stream sent to the combustion turbine would be primarily predominantly hydrogen, which would require a turbine configuration specifically optimized for hydrogen fuel to achieve efficient operation (Katzer, James, et al., 2007, p. 34). The CO_2 removed from the syngas would be compressed into liquid form and stored prior to being transferred for geologic sequestration or other use such as enhanced oil recovery.

The addition of carbon capture to the design of an IGCC facility would result in significantly higher capital and operating costs, along with lower overall fuel efficiency. Increased capital costs are the result of the additional equipment required for carbon capture and increased infrastructure required to support the carbon capture equipment (for example, water, steam, electrical, piping, etc.). Higher operating costs are associated with increased maintenance requirements and the energy requirements of the carbon capture equipment. Increased energy requirements for carbon capture equipment result primarily because of compressing

the CO_2 to a high-pressure liquid and providing steam for shift reaction (Katzer, James, et al., 2007, pp. 34-35).

Retrofitting an Existing IGCC Plant for Carbon Capture

Retrofitting an IGCC unit for CO_2 capture involves significant changes in the core of the gasification/ combustion/power generation train. The choice of the gasifier (slurry feed, dry feed), gasifier configuration (full-quench, radiant cooling, convective syngas coolers), acid gas clean-up, operating pressure, and gas turbine are dependent on whether a "no-capture" or a "capture" plant is being built (Katzer, James, et al., 2007. p. 38). No-capture designs (that is, IGCC designs that do not incorporate carbon capture) tend to favor lower pressure and increased heat recovery from the gasifier train (radiant coolers and even syngas coolers) to raise more steam for the steam turbine, resulting in a higher net generating efficiency. Dry feed gasifiers provide the highest efficiency and are favored for coals with lower heating value, largely because of their higher moisture content; but the capital costs are higher (Katzer, James, et al., 2007. p. 38).

Capture designs (that is, IGCC designs that incorporate carbon capture) favor higher-pressure operation, slurry feed gasifiers, and full-quench mode. In addition, the design of a high-efficiency combustion turbine for high hydrogen concentration feeds is different from combustion turbines optimized for syngas, requires further development, and has very little operating experience (Katzer, James, et al., 2007. p. 38).

In summary, an optimum IGCC unit design for no CO_2 capture is quite different from an optimum unit design for CO_2 capture (Katzer, James, et al., 2007. p. 38). Nonetheless, it appears that retrofitting a no-capture IGCC unit with carbon capture equipment would be possible, although the resulting system would be expected to be less than optimal in terms of plant efficiency.

Geologic Sequestration

Geologic sequestration involves the injection of captured CO_2 into underground reservoirs that have the ability to securely contain it over long periods of time. The U.S. Department of Energy (DOE) is taking a lead role in advancing the state of sequestration knowledge and technology via its Carbon Sequestration Program. The primary objective of DOE-sponsored research is to develop technologies to cost-effectively store and monitor CO_2 in geologic formations. Accomplishing this involves improved understanding of CO_2 flow and trapping within the reservoir and the development and deployment of technologies such as simulation models and monitoring systems. Experience gained from carbon sequestration field tests will facilitate the development of best practice manuals to ensure that sequestration does not impair the geologic integrity of underground reservoirs, thus assuring secured and environmentally acceptable CO_2 storage.

DOE-sponsored research is concentrated on five types of geologic formations, each presenting unique challenges and opportunities. These formations include oil and gas reservoirs, deep saline formations, un-mineable coal seams, oil and gas rich organic shales, and basalts.

Because of their prevalence worldwide, saline formations may present the highest CO_2 sequestration capacity among the various geologic formation types. There is already one example of demonstrated commercial-scale sequestration in a saline formation. In 1996, prompted by the Norwegian tax on carbon dioxide, the oil company Statoil began taking unwanted carbon dioxide from the Sleipner West field in the Norwegian North Sea and storing it 1,000 meters beneath the seabed in a saline aquifer reservoir. Since 1996, about 1 million metric tons of carbon dioxide per year have been injected into the Utsira saline aquifer (U.S. Energy Information Administration, 2008).

DOE's carbon sequestration atlas suggests that deep saline formations may be present in White Pine County to some extent. Saline formations are composed of porous rock saturated with brine and capped by one or more regionally extensive impermeable rock formations enabling trapping of injected CO_2. Compared to coal seams or oil and gas reservoirs, saline formations are more common and offer the added benefits of greater proximity, higher CO_2 storage capacity, and fewer existing well penetrations. On the other hand, much less is known about the potential of saline formations to store and immobilize CO_2 since each aquifer is unique and not all aquifers will be suitable for sequestration. Additional research will be needed to understand the potential for deep saline formations to store captured CO_2 in White Pine County and elsewhere.

Geologic Sequestration

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Appendix A

Classification of Solid Fuels

APPENDIX A

Classification of Solid Fuels

Coal is classified into four main types, or ranks, - lignite, subbituminous, bituminous and anthracite.

Lignite is the lowest rank of coal with the lowest energy content. Approximately 20 lignite mines exist in the United States, producing about 7 percent of U.S. coal with most lignite mined in Texas and North Dakota. Lignite is generally characterized by low heating value and high moisture content making it uneconomical to transport over long distances.

Subbituminous coal has a higher heating value than lignite. Most subbituminous coal in the U.S. is at least 100 million years old. About 42 percent of the coal produced in the United States is subbituminous and is used to generate electricity. Subbituminous is generally characterized by a mid-range heating value, low sulfur content and economical supply making it attractive to transport over long distances. Over the last two decades many power plants have switched to a low sulfur subbituminous coal for environmental compliance. Wyoming is the leading source of subbituminous coal.

Bituminous coal has over twice the heating value of lignite. Bituminous coal was formed under high heat and pressure and in the United States is between 100 to 300 million years old. It is the most abundant rank of coal found in the United States, accounting for about half of U.S. coal production. Bituminous coal is generally characterized by its high heat content, and often higher sulfur and ash content than subbituminous. Bituminous coal is used to generate electricity and is an important fuel and raw material for the steel and iron industries. West Virginia, Kentucky, and Pennsylvania are the largest producers of bituminous coal.

Anthracite contains 86 to 97 percent carbon, and has a heating value slightly lower than bituminous coal. It is very rare in the United States, accounting for less than one-half of a percent of the coal mined in the U.S. Anthracite is used principally for heating homes and in gas production. All of the anthracite mines in the United States are located in northeastern Pennsylvania.

Other Solid Fuels

Waste coal is usable coal refuse that is a byproduct of previous processing operations or is recaptured from mining tailings. Examples include bituminous gob, fine coal, lignite waste, coal recovered from a refuse bank or slurry dam, and coal recovered by dredging.

Petroleum (pet) coke is a byproduct of petroleum refining processes. A residue left over from the refining of crude oil can be further refined by "coking" it at high temperatures and under great pressure. The resulting product is petcoke, a hard substance similar in some respects to coal. Petcoke is generally characterized by its high heat content, high sulfur content and low ash. Approximately 60 to 70 million tons of petcoke are produced worldwide, with most produced at coastal refineries in North and South America.

Appendix I

Wetlands

APPENDIX I

Wetlands

The purpose of the wetland inventory was to (1) identify all wetlands within the White Pine Energy Station study area, including buffer zones, and (2) obtain USACE concurrence for the inventory results and determination of jurisdiction. Discussions regarding specific impacts to wetlands and other waters of the U.S. as the result of construction and operation of specific project features are described in Chapter 4 of the EIS. Tables 4.5-1 (Proposed Action) and 4.5-2 (Alternative 1) in Chapter 4 summarize temporary and permanent project-related impacts to wetlands.

Because USACE jurisdictional determinations are yet to be made for the study area, all areas identified in the following table are potential USACE jurisdictional wetlands or potential Waters of the United States.

USACE Non-Jurisdictional Wetlands (unshaded rows), USACE Jurisdictional Wetlands (shaded gray rows) and Waters of the United States, and NDEP-Sensitive Waters in the White Pine Energy Station Project Area

Project Components/Wetlands*	USACE Non-jurisdictional Wetlands (acres)	USACE Jurisdictional Wetlands (acres)	Total (acres)
Proposed Action			
Preferred Rail Spur ROW			
RSP1_AM_1a, 1b_jw		40.5	40.5
RSP1_RM_1_njw	20.4		20.4
RSP1_WM_1a_jw		0.23	0.23
RSP Total	**20.4**	**40.8**	**61.1**
Preferred SWIP ROW			
SP1_AM_1a, 1b, 1c_jw		58.6	58.6
SP1_RM_1a, 1b_njw	13.9		13.9
SP1_WM_1a, 1b_jw		27.11	27.11
SP Total	**13.9**	**85.7**	**99.6**
Preferred Water Pipeline			
WPP1_RM_1_njw	2.5		2.5
Proposed Action Total	36.8	126.5	163.3
Alternative 1			
Alternative 1 Rail Spur ROW			
RSA1_WM_1_jw		4.8	4.8
RSA2_WM_1_jw		0.62	0.6
RSA3_RM_1_njw	0.06		0.1
RSA4_RM_1_njw	0.21		0.2
RSA5_RM_1_njw	0.15		0.1
RSA6_AM_1a,1b_jw		0.61	0.67

USACE Non-Jurisdictional Wetlands (unshaded rows), USACE Jurisdictional Wetlands (shaded gray rows) and Waters of the United States, and NDEP-Sensitive Waters in the White Pine Energy Station Project Area

Project Components/Wetlands*	USACE Non-jurisdictional Wetlands (acres)	USACE Jurisdictional Wetlands (acres)	Total (acres)
RSA6_RM_1a,1b,1c,1d_njw	1.4		46.80
RSA6_WM_1a,1b_jw		1.7	5.32
RSA6 total	**46.8**	**6.0**	**52.8**
RSA Total	**47.2**	**11.4**	**58.6**
Alternative 1 SWIP ROW			
SA1_AM_1a,1b,1c,1d_jw		48.84	48.84
SA1_AM_1e,1f,1g_njw	7.21		7.21
SA1_RM_1a,1b,1c,1d_njw	56.78		56.78
SA1_WM_1a,1b_jw		30.13	30.13
SA Total	**64.0**	**79.0**	**143.0**
Alternative 1 Water Pipeline			
WPA1_AM_1a,1b_njw	0.29		0.29
WPA1_RM_1a,1b_njw	7.17		7.17
WPA1 total	7.5		7.5
WPA2_AM_1a,1b_njw	0.51		0.51
WPA2_RM_1_njw_	3.8		3.8
WPA2 total	**4.3**		**4.3**
WPA3_AM_1a_njw	1.3		1.3
WPA3_AM_1b,1c_jw		19.6	19.6
WPA3_RM_1a,1b,1d,1e_njw	6.81		6.81
WPA3_RM_1c_jw		2.0	2.0
WPA3_WM_1a_jw		1.5	1.5
WPA3 total	**8.1**	**23.1**	**31.2**
WPA4_RM_1_njw	6.6		6.6
WPA5_WM_1_njw	0.02		0.0
WPA6_RM_1_njw	0.04		0.0
WPA7_RM_1_njw	0.37		0.4
WPA8_RM_1a,1b_njw	3.1		3.1
WPA9_AM_1_jw		0.26	
WPA9_RM_1_njw	4.1		
WPA9 total	**4.1**	**0.3**	**4.4**
WPA Total	**34.2**	**23.4**	**57.5**
Alternate 1 Total	**145.4**	**113.8**	**259.1**
Wetland Totals	**182.1**	**240.3**	**422.4**

* rsa = rail spur alternative 1, rsp = rail spur preferred alternative, wpa = water pipeline alternative 1. wpp = water pipeline preferred alternative, SA = SWIP transmission line alternative 1, SP = SWIP transmission line preferred alternative. WM = wet meadow, AM = alkali meadow, RM = rabbitbrush meadow, jw = jurisdictional wetland, njw = non-jurisdictional wetland. 1a, 1b, 1c - individual wetland polygons.

USACE Drainages

Other Waters of the U.S.	Ephemeral/Swale-like Drainages	Acreage	Number
Duck Creek Segments[a]			
rsp26-jd – intermittent		2.014	1
sp58-jd – intermittent		7.166	1
sa12-jd – intermittent		8.844	1
sa11-jd – intermittent		0.926	1
Schell Creek Segments			
wpp90-jd – perennial		0.206	1
wpp89-jd – intermittent		0.116	1
Total		**19.273**	**6**
NDEP Sensitive Surface Waters[b]			
NDEP Drainage[c]			**Numbers**[d]
	60		66

[a] Includes 3 mainstem sections of Duck Creek and one side channel.
[b] USACE jurisdictional wetlands are also NDEP jurisdictional sensitive habitats = 240.3 acres.
[c] Drainages with potential for water quality impairment from construction-related ground disturbances.
[d] Acreages were not calculated for the 60 ephemeral and swale-like drainages since several do not contain an ordinary high water mark (OHWM) normally used to calculate acreages (for USACE jurisdiction).

Appendix J

Biological Resources Supplemental Information

APPENDIX J

Biological Resources Supplemental Information

This appendix contains four sections as follows:

- A table listing the common and scientific names used in this document (Table J-1)
- A table listing wildlife observed and with high potential to occur in the WPES project area (Table J-2)
- Background information on flora and fauna and on Threatened, Endangered, Candidate, and Sensitive Species
- Risk Assessment for Noxious/Invasive Weeds

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
Plants	
African rue	*Peganum harmala*
alkali bluegrass	*Poa juncifolia*
alkali cordgrass	*Spartina gracilis*
alkali sacaton	*Sporobolus airoides*
American kochia	*Kochia scoparia*
antelope bitterbrush	*Purshia tridentata*
Austrian fieldcress	*Rorippa austriaca*
Austrian peaweed	*Sphaerophysa salsula / Swainsona salsula*
Baltic rush	*Juncus balticus*
basalt springparsley	*Cymopterus basalticus*
basin big sagebrush	*Artemisia tridentata* var. *tridentata*
black henbane	*Hyoscyamus niger*
black sagebrush	*Artemisia nova*
broad-pod freckled milkvetch	*Astragalus lentiginosus* var. *latus*
broom snakeweed	*Gutierrezia sarothrae*
budsage	*Artemisia spinescens*
bur buttercup	*Ranunculus testiculatus*
bushy blazingstar	*Mentzelia dispersa*
camelthorn	*Alhagi camelorum*
Canada thistle	*Cirsium arvense*
Carolina horse-nettle	*Solanum carolinense*
cattail	*Typha latifolia*

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
cheatgrass	*Bromus tectorum*
clustered field sedge	*Carex praegracilis*
common crupina	*Crupina vulgaris*
common dandelion	*Taraxacum officinale*
creeping spikerush	*Eleocharis* cf. *palustris*
curl-leaf mountain mahogany	*Cercocarpus ledifolius*
cushion buckwheat	*Eriogonum ovalifolium*
cushion stenotus	*Stenotus acaulis*
dainty moonwort	Dainty moonwort
dainty moonwort	*Botrychium crenulatum*
dalmation toadflax	*Linaria dalmatica*
desert paintbrush	*Castilleja chromosa*
diffuse knapweed	*Centaurea diffusa*
dusty maidens	*Chaenactis douglasii*
Dyer's woad	*Isatis tinctoria*
Eastwood milkweed	*Asclepias eastwoodiana*
Eurasian water-milfoil	*Myriophyllum spicatum*
fiddleneck hawkweed	*Crepis runcinata*
field bindweed	*Convolvulus arvensis*
flixweed	*Descurainia sophia*
fourwing saltbrush	*Atriplex canescens*
giant reed	*Arundo donax*
giant salvinia	*Salvinia molesta*
goats rue	*Galega officinalis*
gray rabbitbrush	*Chrysothamnus nauseosus*
greasewood	*Sarcobatus vermiculatus*
Great Basin wildrye	*Leymus cinereus*
green fountain grass	*Pennisetum setaceum*
green rabbitbrush	*Chrysothamnus viscidiflorus*
hanging bladderpod	*Lesquerella pendula*
hoary cress	*Cardaria draba*
Holmgren buckwheat	Holmgren buckwheat
Holmgren buckwheat	*Eriogonum holmgrenii*
hornwort	*Ceratophyllum* spp.
houndstongue	*Cynoglossum officinale*
Iberian star thistle	*Centaurea iberica*

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
Indian ricegrass	*Achnatherum hymenoides*
inland saltgrass	*Distichlis spicata*
Johnson grass	*Sorghum halepense*
Klamath weed	*Hypericum perforatum*
leafy spurge	*Euphorbia esula*
Lemmon's rubberweed	*Hymenoxys lemmonii*
low sagebrush	*Artemisia arbuscula*
lupine	*Lupinus argenteus*
Malta star thistle	*Centaurea melitensis*
matted buckwheat	*Eriogonum caespitosum*
mayweed chamomile	*Anthemis cotula*
meadow milkvetch	Meadow milkvetch
meadow milkvetch	*Astragalus diversifolius*
Mediterranean sage	*Salvia aethiopis*
medusahead	*Taeniatherum caput-medusae*
milkvetch	*Astragalus* spp.
Mojave seablite	*Suaeda moquinii*
Monte Neva Indian paintbrush	*Castilleja salsuginosa*
Monte Neva paintbrush	*Castilleja salsuginosa*
Monte Verde paintbrush	*Castilleja salsuginosa*
Mormon tea	*Ephedra viridis*
Mount Wheeler sandwort	*Arenaria congesta* var. *wheelerensis*
mountain big sagebrush	*Artemisia tridentata* ssp. *vaseyana*
mountain mahogany	*Cercocarpus montanus*
musk thistle	*Carduus nutans*
mustards	*Descurainia* spp.
Nachlinger catchfly	*Silene nachlingerae*
Nevada primrose	*Ericameria watsoni*
nodding thelypody	*Thelypodium flexuosum*
non-native invasive cheatgrass	*Bromus tectorum*
Parish phacelia	*Draba pedicellata*
Pennell beardtongue	*Penstemon leiophyllus* var. *francisci-pennellii*
Pennell draba	*Draba pennellii*
pepperweed	*Lepidium perfoliatum*
perennial pepperweed	*Lepidium latifolium*
pinnate tansymustard	*Descurainia pinnata*

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
pinyon	*Pinus monophylla*
poison hemlock	*Conium maculatum*
pondweed	*Potamogeton* spp.
Poverty sumpweed	*Iva axillaries*
poverty weed	*Iva axillaris*
prickly lettuce	*Lactuca serriola*
puncture vine	*Tribulus terrestris*
purple loosestrife	*Lythrum salicaria, L. virgatum, and their cultivars*
purple star thistle	*Centaurea calcitrapa*
rush skeletonweed	*Chondrilla juncea*
rushes	*Juncus* spp.
Russian knapweed	*Acroptilon repens*
Russian thistle	*Salsola kali*
Russian thistle	*Salsola iberica*
salt cedar (tamarisk)	*Tamarix* spp.
salt grass	*Distichlis spicata*
saltlover	*Halogeton glomeratus*
sand cholla	*Opuntia pulchella*
Sandberg bluegrass	*Poa secunda*
Scotch thistle	*Onopordum acanthium*
shadscale	*Atriplex confertifolia*
shadscale spring parsley	Shadscale spring parsley
silverweed	*Potentilla anserine*
Snake Range whitlowcress	*Draba oreibata* v. *serpentine*
snowberry	*Symphoricarpos* sp.
sow thistle	*Sonchus arvensis*
spikerush	*Eleocharis* spp.
spiny hopsage	*Grayia spinosa*
spotted knapweed	*Centaurea maculosa*
squarrose knapweed	*Centaurea virgata Lam.* ssp. *squarrosa*
squirreltail	*Elymus elymoides*
stalked whitlow cress	*Draba pedicillata*
straight-leaf rush	*Juncus* cf. *orthophyllus*
sulphur cinquefoil	*Potentilla recta*
Sunnyside green gentian	*Frasera gypsicola*
Syrian bean caper	*Zygophyllum fabago*

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
thickspike wheatgrass	*Elymus lanceolatus*
Thurber's needlegrass	*Achnatherum thurberiana*
tumble mustard	*Sisymbrium altissimum*
Tunnel Springs beardtongue	*Penstemon concinnus*
Utah juniper	*Juniperus osteosperma*
Utah serviceberry	*Amelanchier utahensis*
Ute ladies'-tresses orchid	*Spiranthes diluvialis*
water hemlock	*Cicuta maculata*
watercress	*Rorippa nasturtium aquatica*
waterthyme	*Hydrilla verticillata*
Watson goldenbush	*Ericameria watsonii*
waxflower	*Jamesia tetrapetala*
western tansymustard	*Descurainia pinnata*
white horse-nettle	*Solanum elaeagnifolium*
White River catseye	*Cryptantha welshii*
willow	*Salix* spp.
winterfat	*Krascheninnikovia lanata*
Wyoming big sagebrush	*Artemisia tridentata* var. *wyomingensis*
yellow starthistle	*Centaurea solstitialis*
yellow toadflax	*Linaria vulgaris*
Mammals	
American badger	*Taxidea taxis*
badger	*Taxidea taxis*
black-tailed jackrabbit	*Lepus californicus*
bobcat	*Lynx rufus*
bushy-tailed woodrat	*Neotoms cinerea*
coyote	*Canis latrans*
dark kangaroo mouse	*Microdipodops megacephalus*
golden-mantled ground squirrel	*Spermophilus lateralis*
gray fox	*Urocyon cinereoargenteus*
gray fox	*Urocyon cinereoargenteus*
ground squirrels	*Spermophilus spp.*
jackrabbit	*Lepus spp.*
kangaroo rat	*Dipodomys spp.*
Kit fox	*Vulpes macrotis*
least chipmunk	*Tamias minimus*

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
mountain lion	*Felis concolor*
mule deer	*Odocoileus hemionus*
Nuttall's cottontail	*Sylvilagus nuttallii*
Piute (Great Basin) ground squirrel	*Spermophilus mollis*
Preble's shrew	*Sorex preblei*
Pronghorn	*Antilocapra americana*
pygmy rabbit	*Brachylagus idahoensis*
pygmy shrew	*Sorex minutus*
Richardson's ground squirrel	*Spermophilus elegans nevadensis*
rock squirrel	*Spermophilus variegates*
sagebrush vole	*Lagurus curtatus*
Townsend's ground squirrel	*Spermophilus townsendii*
white-tailed antelope squirrel	*Ammospermophilus leucurus*
Bats	
California myotis	*Myotis californicus*
fringed myotis	*Myotis thysanodes*
little brown bat	*Myotis lucifugus*
pallid bat	*Antrozous pallidus*
spotted bat	*Euderma maculatum*
Townsend's big-eared bat	*Corynorhinus townsendii*
western small-footed myotis	*Myotis ciliolabrum*
Birds	
American avocet	*Recurvirostra americana*
American crow	*Corvus brachyrhynchos*
American kestrel	*Falco sparverius*
bald eagle	*Haliaeetus leucocephalus*
black-billed magpie	*Pica hudsonia*
black-throated gray warbler	*Dendroica nigrescens*
bobolink	*Dolichonyx oryzivorus*
Brewer's sparrow	*Spizella breweri*
Canada goose	*Branta canadensis*
common nighthawk	*Chordeiles minor*
common raven	*Corvus corax*
Cooper's hawk	*Accipiter cooperi*
eared grebe	*Podiceps nigricollis*
European starling	*Sturnus vulgaris*

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
ferruginous hawk	*Buteo regalis*
golden eagle	*Aquila chrysaetos*
gray vireo	*Vireo vicinior*
great horned owl	*Bubo virginianus*
greater sage-grouse	*Centrocercus urophasianus*
green-tailed towhee	*Pipilo chlorurus*
green-winged teal	*Anas crecca*
gulls	*Larus* spp.
horned lark	*Eremophila alpestris*
house sparrow	*Passer domesticus*
juniper titmouse	*Baeolophus griseus*
kestrels	*Falco sparverius*
killdeer	*Charadrius vociferous*
least bittern	*Ixobrychus exilis*
loggerhead shrike	*Lanius ludovicianus*
long-billed curlew	*Numenius americanus*
long-eared owl	*Asio otus*
mallard	*Anas platyrhynchos*
mountain bluebird	*Sialia currucoides*
mountain chickadee	*Poecile gambeli*
mourning dove	*Zenaida macroura*
northern flicker	*Colaptes auratus*
northern goshawk	*Accipiter gentiles*
northern harrier	*Circus cyaneus*
northern pintail	*Anas acuta*
peregrine falcon	*Falco peregrinus*
pinyon jay	*Gymnorhinus cyanocephalus*
prairie falcon	*Falco mexicanus*
red-tailed hawk	*Buteo jamaicensis*
red-winged blackbird	*Agelaius phoeniceus*
relict dace	*Relictus solitarius*
rough-legged hawk	*Buteo lagopus*
sage sparrow	*Amphispiza bellii*
sage thrasher	*Oreoscoptes montanus*
sandhill crane	*Grus Canadensis*
short-eared owl	*Asio flammeus*

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
spotted towhee	*Pipilo maculates*
Swainson's hawk	*Buteo swainsoni*
tricolored blackbird	*Agelaius tricolor*
turkey vulture	*Cathartes aura*
vesper sparrow	*Pooecetes gramineus*
western bluebird	*Sialia mexicana*
western meadowlark	*Sturnella neglecta*
western screech owl	*Otus kennicottii*
western scrub jay	*Aphelocoma californica*
western snowy plover	*Charadrius alexandrinus*
white-faced ibis	*Plegadis chihi*
Wilson's phalarope	*Phalaropus tricolor*
yellow warbler	*Dendroica petechia*
yellow-billed cuckoo	*Coccyzus americanus*
yellow-breasted chat	*Icteria virens*
Amphibians	
Columbia spotted frog	*Rana luteiventris*
Great Basin gopher snake	*Pituophis catenifer deserticola*
northern leopard frog	*Rana pipiens*
Pacific tree frog	*Pseudacris regilla*
spadefoot toad	*Scaphiopus hammondi*
Reptiles	
Great Basin gopher snake	*Pituophis catenifer deserticola*
Great Basin rattlesnake	*Crotalus viridis lutosus*
horned lizard	*Phrynosoma platyrhinos*
Northern desert horned lizard	*Phrynosoma platyrhinos*
sagebrush lizard	*Sceloporus graciosus*
short-horned lizard	*Phrynosoma douglassii*
western fence lizard	*Sceloporus occidentalis*
Insects	
Baking Powder Flat blue	*Euphilotes bernardino minuta*
dark sandhill skipper	*Polites sabuleti nigrescens*
Koret's checkerspot	*Euphydryas editha koreti*
Steptoe Valley crescentspot	*Phyciodes pascoensis arenacolor*
White River wood nymph	*Cercyonis pegala pluvialis*

TABLE J-1
Common and Scientific Names

Common Name	Scientific Name
Springsnails	
Northern Steptoe springsnail	*Pyrgulopsis serrata*
Pulmonates	*Physa* ssp., *Lymnaea* ssp., *Gyraulus* ssp., and *Fossaria* ssp.
southern Steptoe pyrg	*Pyrgulopsis sulcata*
springsnail	*Pyrgulopsis serrata*
Fish	
brook trout	*Salvelinus fontinalis*
largemouth bass	*Micropterus salmoides*
northern pike	*Esox lucius*
rainbow trout	*Oncorhynchus mykiss*
relict dace	*Relictus solitarius*
tiger trout	*Salmo trutta x Salvelinus fontinalis*
Utah chub	*Gila atraria*

TABLE J-2
Wildlife Observed or with High Potential to Occur in the WPES Project Area

Scientific Name	Common Name	Observed (Y/N)	Habitat Type in Project Area
Birds			
Lanius ludovicianus	Loggerhead shrike	Y	Sagebrush/Pinyon-Juniper
Eremophilia alpestris	Horned lark	Y	Sagebrush
Oreoscoptes montanus	Sage thrasher	Y	Sagebrush
Amphispiza bellii	Sage sparrow	Y	Sagebrush
Spizzela breweri	Brewer's sparrow	N	Sagebrush
Sialia mexicana	Western bluebird	Y	Sagebrush/Pinyon-Juniper
Sturnella neglecta	Western meadowlark	Y	Sagebrush/Pinyon-Juniper
Corvus corax	Common raven	Y	All
Circus cyaneus	Northern harrier	Y	Sagebrush
Chordeiles minor	Common nighthawk	Y	Sagebrush/Pinyon-Juniper
Charadrius vociferous	Killdeer	Y	Wetlands/Salt Desert Scrub
Sialia currucoides	Mountain bluebird	Y	Pinyon-Juniper
Gymnorhinus cyanocephalus	Pinyon jay	Y	Pinyon-Juniper
Aphelocoma californica	Western scrub jay	Y	Pinyon-Juniper
Poecile gambeli	Mountain chickadee	Y	Pinyon-Juniper

TABLE J-2
Wildlife Observed or with High Potential to Occur in the WPES Project Area

Scientific Name	Common Name	Observed (Y/N)	Habitat Type in Project Area
Dendroica nigrescens	Black-throated gray warbler	Y	Pinyon-Juniper
Dendroica petechia	Yellow warbler	Y	Pinyon-Juniper near streams
Falco sparverius	American kestrel	Y	Sagebrush/Pinyon-Juniper
Pipilo chlorurus	Green-tailed towhee	N	Sagebrush
Falco mexicanus	Prairie falcon	Y	Sagebrush/Pinyon-Juniper
Falco peregrinus	Peregrine falcon	N	Cliff ledges in Pinyon-Juniper
Accipiter cooperi	Cooper's hawk	N	Pinyon-Juniper woodland and woodland edges
Buteo swainsoni	Swainson's hawk	N	Pinyon-Juniper/isolated trees
Buteo jamaicensis	Red-tailed hawk	Y	All
Pica hudsonia	Black-billed magpie	Y	Sagebrush/Pinyon-Juniper
Buteo lagopus	Rough-legged hawk	N	Agricultural fields, Grasslands
Aquila chrysaetos	Golden eagle	Y	Sagebrush/Pinyon-Juniper
Pooecetes gramineus	Vesper sparrow	N	Sagebrush
Pipilio maculates	Spotted towhee	Y	Pinyon-Juniper
Asio otus	Long-eared owl	N	Woodlands
Asio flammeus	Short-eared owl	N	Grasslands, Sand Dunes, Marshes
Otus kennicottii	Western screech owl	N	Forest edges, Tree cavities
Bubo virginianus	Great horned owl	N	Pinyon-Juniper woodlands
Cathartes aura	Turkey vulture	Y	All
Corvus brachyrhynchos	American crow	Y	All
Agelaius phoeniceus	Red-winged blackbird	Y	Wetland
Numenius americanus	Long-billed curlew	Y	Wetland/Duck Creek
Recurvirostra americana	American avocet	Y	Wetland/Duck Creek
Anas acuta	Northern pintail	Y	Wetland/Duck Creek
Grus canadensis	Sandhill crane	Y	Wetland/Duck Creek
Branta canadensis	Canada goose	N	Wetlands/Aquatic Habitats, Agricultural
Anas platyrhynchos	Mallard	N	Wetlands/Shallow Aquatic Habitats
Anas crecca	Green-winged teal	N	Aquatic Habitats/Winter Resident
Centrocercus urophasianus	Greater sage-grouse	Y	Sagebrush
Colaptes auratus	Northern flicker	Y	Pinyon-Juniper

TABLE J-2
Wildlife Observed or with High Potential to Occur in the WPES Project Area

Scientific Name	Common Name	Observed (Y/N)	Habitat Type in Project Area
Mammals			
Canis latrans	Coyote	Y	All
Vulpes macrotis	Kit fox	N	Sagebrush
Urocyon cinereoargenteus	Common gray fox	Y	Rocky, mountain forests
Odocoileus hemionus	Mule deer	Y	Sagebrush
Antilocarpa americana	Pronghorn	Y	Sagebrush
Lepus californicus	Black-tailed jackrabbit	Y	All
Sylvilagus nutallii	Mountain cottontail	Y	Sagebrush/Pinyon-Juniper
Brachylagus idahoensis	Pygmy rabbit	Y	Sagebrush
Spermophilus elegans nevadensis	Richardson's ground squirrel	N	Rocky habitats in Pinyon-Juniper/Sagebrush
Amnospermophilus leucurus	White-tailed antelope squirrel	N	Sagebrush
Spermophilus lateralis	Golden-mantled ground squirrel	N	Sagebrush
Spermophilus townsendii	Townsend's ground squirrel	N	Sagebrush
Spermophilus variegates	Rock squirrel	N	Rocky habitats in Pinyon-Juniper
Spermophilus mollis	Piute (Great Basin) ground squirrel	N	Sagebrush
Tamias minimus	Least chipmunk	N	Rocky habitats in Pinyon-Juniper
Taxidea taxis	American badger	N	Sagebrush
Sorex minutus	Pygmy shrew	N	Sagebrush
Felis concolor	Mountain lion	N	Pinyon-Juniper
Antrozous pallidus	Pallid bat	N	Rocky cliffs, Low scrub
Corynorhinus townsendii	Townsend's big-eared bat	N	Caves and mines
Euderma maculatum	Spotted bat	N	Caves, rock crevices
Myotis californicus	California myotis	N	Coniferous forest, cliffs, caves
Myotis cilioabrum	Western small-footed myotis	N	Rocky cliffs, forested, grassland
Myotis lucifugus	Little brown myotis	N	Coniferous forest , riparian
Amphibians			
Rana pipiens	Northern leopard frog	Y	Aquatic
Fish			
Relictus solitarius	Relict dace	Y	Aquatic

TABLE J-2
Wildlife Observed or with High Potential to Occur in the WPES Project Area

Scientific Name	Common Name	Observed (Y/N)	Habitat Type in Project Area
Reptiles			
Pituophis catenifer deserticola	Great Basin gopher snake	Y	Wetland
Sceloporus graciosus	Sagebrush lizard	Y	Sagebrush
Sceloporus occidentalis	Western fence lizard	Y	Sagebrush/Pinyon-Juniper
Phrynosoma platyrhinos	Northern desert horned lizard	Y	Sagebrush
Crotalus viridus lotus	Western/Great Basin rattlesnake	Y	Sagebrush

Background Information on Flora and Fauna and on Threatened, Endangered, Candidate, and Sensitive Species

Federally Protected Species

Bald Eagle

In the western United States, bald eagles nest near waterways that provide abundant food sources and build their nests in large trees. However, historical records indicate bald eagles utilized cliffs for nesting near Pyramid Lake, Nevada (Linsdale, 1936 as cited in FWS, 1986) and in 1985, a pair nested on a cliff on an island at Pyramid Lake, Nevada (FWS, 1986). They usually nest the same territories each year and often use the same nests repeatedly. Their home range is between 1,700 and 10,000 acres, depending on food availability.

Bald eagles prey on a wide variety of fish, waterfowl, small mammals, and carrion (Stalmaster, 1986). In portions of the western United States, eagles forage on warm-water and non-game fish, waterfowl, and small mammals (FWS, 1986). Areas that provide open water, wetlands, shrub steppe, and other foraging habitats near forests or single large trees are particularly important for bald eagles. Because of the lack of water, wintering eagles in Nevada occur as small groups near isolated water bodies and often prey on jackrabbits (*Lepus* spp.) (FWS, 1986). During winter, bald eagles use perches that are near food sources. Bald eagles commonly perch on artificial structures such as powerline poles and towers. Night roosts used during winter typically provide eagles with protection from the weather. Wintering eagles sometimes roost in permanent communal night roosts, with multiple birds per tree, although eagles also roost individually.

Yellow-Billed Cuckoo

The yellow-billed cuckoo is relatively common east of the Rocky Mountains, but habitat degradation and loss of riparian habitat in the West has led to the cuckoo's candidate status. The yellow-billed cuckoo's historic breeding range extended through most of North America from southern Canada to Mexico. The recent range of yellow-billed cuckoos includes populations in Arizona, New Mexico, and California (66 FR 38611). Historically, yellow-

billed cuckoos were found along the lower Truckee River, Lahontan Valley (Oakleaf, 1974), and along the Colorado River in southern Nevada (Neel, 1999). The most recent documentation of the yellow-billed cuckoo nesting in Nevada was a pair in observed in Lincoln County in 1979. Since 1990, there have been only sporadic sightings of single birds in Nevada (Neel, 1999). Surveys conducted in 2000 by NDOW (2001, as cited in 66 FR 38611) in southern Nevada documented 19 yellow-billed cuckoo (4 pairs and 11 unpaired birds) with no nests being found. NDOW estimated the summer population of yellow-billed cuckoo is between 20 and 30 birds statewide.

The yellow-billed cuckoo is a riparian obligate species that requires dense cottonwood-willow forested tracts of at least 16.8 hectares, including a minimum of 3.0 hectares of closed-canopy broadleaf forest (Laymon and Halterman, 1987). A wide band of cottonwood canopy closure is required, as is a healthy midstory of willow (Gaines and Laymon, 1984; Laymon and Halterman, 1987; Franzreb and Laymon, 1993; Hughes, 1999). In addition, cuckoos appear to prefer dense understory foliage as an important habitat component.

State Protected Species

Townsend's Big-Eared Bat

Townsend's big-eared bat is found throughout western North America from British Columbia south to the Isthmus of Tehuantepec, eastward to the Black Hills of South Dakota, across western Texas, and eastward to the Edwards Plateau. Isolated populations exist in the gypsum caves of northeastern Texas, Oklahoma, and Kansas, and in limestone regions of Arkansas, Missouri, Illinois, Indiana, Ohio, Kentucky, Virginia, and West Virginia (NatureServe, 2006). This species is found primarily in abandoned mines and caves, but is rarely found in crevices. This species is usually associated with forested community types and riparian areas. Townsend's big-eared bats migrate in the winter and reproduce in late spring to early summer. Like most bats, this species is an insectivore and will eat moths and caddisflies. Townsend's big-eared bat tends to hibernate singly, but can occur in clusters during winter in some areas (Schmidly, 1991).

Pallid Bat

The pallid bat is found in Western North America from south-central British Columbia (Okanagan Valley; low numbers) south through the western U.S. to southern Baja California, central Mexico, southern Kansas, southern Texas; and Cuba (NatureServe, 2006). The pallid bat often roosts in colonies of between 20 and several hundred individuals. Summer maternity colonies are found within warm rock crevices, abandoned mines, caves, hollow trees, and in cavern-like building features (for example, attics). This species has also been documented roosting in large conifer snags (Texas State Parks, 2006). This species breeds between October and February. Young are generally born between May and July depending on local climatic variables. Female pallid bats can give birth to a single pup, twins, and sometimes triplets, with twins being most common. Maternity colonies disband between August and October (Texas State Parks, 2006). This species remains relatively inactive during the winter, but is not known to migrate. Pallid bats are believed to hibernate as solitary individuals or in small numbers. Occasional winter activity has been reported in southern portions of its range. Pallid bats are primarily insectivorous, and feed from the ground and occasionally when in flight (Texas State Parks, 2006).

Spotted Bat

The spotted bat is a former Candidate species and is currently a state protected species as well as a BLM sensitive species. The spotted bat's range is from eastern Washington, Oregon, and California, east to Idaho, Montana, Arizona, Utah, western Colorado, and Texas, and though New Mexico and Utah (NatureServe, 2006). This species is primarily solitary, but has been known to roost in small groups. The spotted bat's roost sites are consistently associated with caves, and in cracks and crevices in cliffs and canyons (NatureServe, 2006). This species is found in a variety of habitats including desert to montane coniferous stands of open ponderosa pine, pinyon-juniper woodland, canyon bottoms; open pasture and hayfields; and herbaceous wetlands and riparian areas (NatureServe, 2006). Young are believed to be born in mid-to-late June depending on the local climate. This species feeds primarily on nocturnal beetles and moths. The pallid bat occupies coniferous stands in summer and migrates to lower elevations in late summer/early fall (NatureServe, 2006).

Western Small-Footed Myotis

The western small-footed myotis occurs throughout western North America from southern Saskatchewan, southern Alberta, and southern British Columbia south through the western United States (not including coastal areas north of southern California) into central Mexico (NatureServe, 2006). This species inhabits desert, badland, and semiarid habitats, and more mesic habitats in the southern part of its range (NatureServe, 2006). This myotis prefers to forage on small insects over rocks instead of water. During the summer it roosts in rock crevices, caves, tunnels, under boulders, beneath loose bark, or in buildings. Maternity colonies are often found in barns and buildings (NatureServe, 2006). The western small-footed myotis hibernates in caves and mines. Young are born late May through July.

Little Brown Myotis

The little brown myotis is widespread in North America from Alaska-Canada boreal forests south through most of the contiguous U.S. This species is generally missing from the southern Great Plains region (NatureServe, 2006). The southwestern populations formerly assigned to this species have now been assigned to *M. occultus* (Piaggio et al., 2002; Simmons, in Wilson and Reeder in prep.). As a result, the southwestern boundary of its range includes southern California (except extreme southeast), Nevada, northern Utah, northern Colorado, and perhaps northeastern New Mexico (Piaggio et al. 2002; NatureServe, 2006). The little brown myotis gives birth to one young in late spring to early summer. Winter concentrations may include tens of thousands. Little information is available for summer range. Studies have shown that this species has adapted to using human-made structures for resting and maternity sites; it also uses caves and hollow trees (NatureServe, 2006). The little brown myotis generally forages on flying insects in woodlands near water (NatureServe 2006). During winter, this species requires a relatively constant temperature of about 40 degrees F and 80 percent relative humidity. They will use caves, tunnels, abandoned mines, and similar sites. Maternity colonies are commonly found in warm sites in buildings and other structures, and occasionally this species will use hollow trees.

California Myotis

The Californian myotis occurs in western North America, from extreme southern Alaska south through British Columbia and the western U.S. to southern Baja California and

Guatemala (Wilson and Reeder, 1993). In the U.S., this species is found throughout the desert Southwest, and in lowlands to Montana, Utah, and Colorado. The full extent of the California myotis winter range is unknown, though it has been found in California, Nevada, Utah, Arizona, and Texas (Barbour and Davis, 1969). This species is found at elevations up to 6,000 feet. Females give birth to a single young between late May and mid-June. This species forages on insects from the air over forested and riparian/wetland areas. It is known to hibernate, but active bats regularly have been caught in Nevada in fall and winter, frequently in temperatures below 43 degrees F.

Ferruginous Hawk

The ferruginous hawk is known to breed in eastern Oregon and Washington, southern Alberta, southern Saskatchewan, extreme southwest Manitoba, northern Nevada, Utah, Wyoming, Montana, North Dakota, South Dakota, Nebraska, New Mexico, Arizona, and Colorado. This species is a non-breeding resident primarily in the southwestern and south-central U.S., south to Baja California and in the central mainland of Mexico. Non-breeding species have the greatest numbers in western Texas, eastern New Mexico, and western Oklahoma (Root, 1988; NatureServe, 2006).

The ferruginous hawk inhabits grasslands and sagebrush habitats in western North America. Within the BLM Ely District, the greatest percentages of ferruginous hawk nest sites are within juniper stringers on big sagebrush or black sagebrush knolls and within 2 miles of white sage (Perkins 1982). Mature ferruginous hawks arrive on their breeding grounds late February-early March. This species can be found within their breeding habitat from late February through early October.

Ferruginous hawk density and productivity are closely associated with cycles in prey abundance (Woffinden, 1975; NatureServe, 2006). During the breeding season, this species primarily feeds upon mammals, but they are also known to prey upon other birds, amphibians, reptiles, and insects (NatureServe 2006). Habitat suitability also takes into account the vulnerability of prey species. Ferruginous hawks avoid dense vegetation that reduces their ability to see prey.

Greater Sage-grouse

The greater sage-grouse is a ground dwelling bird that can grow up to 2 feet in height and 30 inches in length (FWS, 2004). This species can be found in elevations ranging from 4,000 to over 9,000 feet.

The greater sage-grouse is a species of concern in Nevada because of a decline in suitable habitat, which has resulted from unsuitable land uses and management of sagebrush ecosystems. Overgrazing, increased land clearing for agricultural purposes, and invasion of non-native species have negatively impacted sagebrush ecosystems and have made these communities more susceptible to severe wildfire outbreaks (Paige and Ritter, 1999).

In Nevada, some livestock management practices have altered greater sage-grouse habitat over the past 100 years. Livestock facilities such as spring developments, water pipelines, and fencing can lead to distribution of livestock into areas previously undisturbed, contributing to long-term changes in plant communities that can reduce the overall health of sagebrush habitats (BLM, 2000). Severe wildfire and the spread of invasive and noxious

weeds also significantly alter sagebrush ecosystems to the detriment of the greater sage-grouse. Power lines, fences, roads, and urban development have an adverse impact on greater sage-grouse populations (Braun 1998). These types of structures provide perches for raptor species to prey on greater sage-grouse and can also lead to greater sage-grouse mortality as a result of collision with guy wires (BLM, 2000). Another threat to greater sage-grouse in Nevada is the expansion of the pinyon-juniper community type in the Great Basin. Encroachment of pinyon-juniper into sagebrush shrubland may lead to a decline in habitat for greater sage-grouse (BLM, 2000).

The greater sage-grouse breeding season extends from mid- March to mid-June. Male greater sage-grouse gather to perform courtship displays in areas known as leks. Leks are defined as "a traditional display ground where two or more male greater sage-grouse have attended in two or more of the previous five years" (Connelly et al., 2003). Leks are usually open areas in sagebrush communities that are surrounded by denser sagebrush cover. Lek sites are the same areas generally used from year to year, assuming new disturbance (natural or man-made) has not forced the grouse to abandon the area.

Studies have shown that large expanses of habitat are needed to allow for connectivity between various residential populations of greater sage-grouse. The majority of greater sage-grouse nests are located under sagebrush plants (Connelly et al., 2004). On average, the most nests are located within 4 miles of the lek, but can be up to 12 miles away from the lek (NDOW, 2004a). Greater sage-grouse nesting habitat consists primarily of big sagebrush communities that have 15-38 percent canopy cover with a grass and forb understory (Connelly et al., 1991, Gregg et al., 1994, Sveum et al., 1998). Brood rearing habitats are used from April through August. Hens will move their broods to moister sites with more succulent vegetation (black sagebrush and low sagebrush) June through July.

In the winter months, the greater sage-grouse diet consists primarily of sagebrush leaves and buds. The taller Wyoming sagebrush is preferred for foraging this time of year. The sagebrush must be at least 10 to 12 inches above snow level to provide both foraging and cover requirements. When snow accumulation is above average, grouse will move down and feed on sagebrush species present at lower elevations (Patterson, 1952, as cited in Connelly et al., 2004).

Pygmy Rabbit

Pygmy rabbits are found in eastern Washington, Oregon, northeastern California, Idaho, Montana, Nevada, western Utah, and southwest Wyoming. Pygmy rabbits inhabit shrublands, typically in dense stands of old growth sagebrush. This species digs its own burrows in deep, loose soils. Distribution of this species is patchy in the Great Basin (NDOW, 2005a).

Pygmy rabbits are active year round and are primarily seen at dusk and dawn. Pygmy rabbits primarily forage on big sagebrush, but will also forage on grasses and forbs in mid-to-late summer (NatureServe, 2006; Green and Flinders, 1980; Lyman, 1991). This species breeds spring to early summer. Threats to this species include habitat loss, predation, introduced diseases, and low population sizes. Protection of well-developed sagebrush is the most effective and practical means of managing and conserving pygmy rabbit habitat.

Risk Assessment for Noxious/Invasive Weeds

Oden, Eric/BOI

From:	Diana Leiker [Diana.Leiker@edaw.com]
Sent:	Wednesday, February 28, 2007 8:41 AM
To:	Oden, Eric/BOI
Subject:	Re: Fwd: White Pine Energy Project-Noxious WeedRisk Assessment
Attachments:	Risk Assessment for Noxious FINAL 070205.doc

Risk Assessment for Noxious Fl...

>>> <Bonnie_Waggoner@nv.blm.gov> 2/5/2007 3:39 PM >>>
Hi Diana -

The Weed Risk Assessment for the White Pine Energy Station EIS is complete and ready to go!

Thanks again!

Bonnie M. Waggoner
Noxious & Invasive Weed Coordinator
Bureau of Land Management - Ely District HC 33 Box 33500 Ely, NV 89301
office: 775-289-1827
cell: 703-244-1705
fax: 775-289-1910

"Diana Leiker" <Diana.Leiker@edaw.com>
02/05/2007 02:09 PM

To
<Bonnie_Waggoner@nv.blm.gov>
cc

Subject
Re: Fwd: White Pine Energy Project-Noxious Weed Risk Assessment

Hi Bonnie,
Your edits have been incorporated into the risk assessment. If you could send me a confirmation email that the risk assessment is complete that would be great. I will send the appropriate BMPs onto the editors for inclusion in the DEIS.

Thanks!

Diana

Diana Leiker
Natural Resource Specialist
EDAW, Inc
1809 Blake St., Suite 200
Denver, CO 80202
303-308-3556

Risk Assessment for Noxious/Invasive Weeds

Project Name: White Pine Energy Project

Directions: This document is intended for electronic use. Adjust the spacing as necessary. Retain one copy of this document with your project files. Provide the Weed Coordinator with a second copy of the form and a project map.

Date Risk Assessment was completed: May 31-June 12, 2004

Steps taken to complete Risk Assessment: EDAW conducted field reconnaissance for biological resources of concern in the White Pine Energy Station (WPES) project area in June 2004 to collect data necessary for completing a National Environmental Policy Act (NEPA) Environmental Impact Statement (EIS) for the proposed action and an alternative action. EDAW used the protocol provided by the Bureau of Land Management (BLM) through the Tri-County Weed Program for all project facilities with the exception of the portion of the proposed transmission line that spans the Egan Range. The protocol involved field teams traveling along the centerline of the proposed corridors for the water pipeline, railroad track spurs, and the transmission power line rights-of-way (ROWs). Both noxious and invasive species were included during data collection for the risk assessment.

At every 0.25 mile, the field teams recorded the approximate density (ocular estimate) of each invasive species present according to the following schedule:

No weed present	0 plants/m^2
Light infestation	1–5 plants/m^2
Moderate infestation	6–25 plants/m^2
Heavy infestation	25–50 plants/m^2
Very heavy infestation	51+ plants/m^2

At each mile point, there was a count of invasive weed species using one square meter (9.6 square feet) quadrat frames. Quadrats were not used for the transmission ROW, because the alignment of the transmission line was not defined at the time surveys were completed. In the Egan Range portion of the SWIP (Southwest Intertie Project) alignment, EDAW selected random points within 0.5-mile-wide SWIP corridor and recorded weed densities accordingly.

If the centerline of a proposed corridor followed a previously existing linear disturbance (such as a road or trail), then one quadrat was placed immediately adjacent to the edge of the disturbance and the second quadrat was placed just outside the roadside/trail infestation on the same side as the first quadrat.

Complete noxious weed mapping will occur prior to construction.

Project Description: The White Pine Energy Project is a coal-fired generation facility to be located on BLM-administered land in Steptoe Valley. Project components with potential impacts to vegetation resources include the power plant ROW, electric transmission facilities ROW, water supply system ROW, rail spur ROW, substation ROW, access ROW, and additional construction ROW (including minerals materials sale), and Moriah Ranches Seeding Project). Table J-3 summarizes project features and approximate long-term and short-term impacts resulting from each feature.

TABLE J-3
Estimated Acres of ROWs and Disturbed and Reclaimed Areas for the Proposed Action

	ROWs		Disturbed and Reclaimed Areas		
	Temporary (acres)[a]	Permanent (acres)[b]	Short-Term[a] (acres)	Reclaimed (acres)	Long-Term[c] (acres)
Power Plant ROW	0	1,281	1,281	0	1,281
Electric Transmission Facilities ROW					
Duck Creek Substation ROW	0	60	60	0	60
Thirtymile Substation ROW	0	77	77	0	77
Duck Creek to Thirtymile 500-kV Line ROW	0	774	249	199	50
Falcon-Gonder 345-kV Interconnection ROW	0	9	8	7	1
SWIP 500 kV Interconnection ROW	0	122	40	34	6
Water Supply System ROW					
Linear Facilities ROW (30-foot wide temporary)	48	0	48	48	0
Linear Facilities ROW (40-foot wide permanent)	0	64	64	48	16
Ground Water Well ROW (8 wells)	0	4	4	3	1
Construction Staging Area ROW	2	0	2	2	0
Rail Spur ROW					
Temporary ROW (30-foot wide)	5	0	5	5	0
Permanent ROW (35- to 70-foot wide)	0	9	9	0	9
Access ROW					
Power Plant ROW Access	0	6	6	0	6
Duck Creek Substation ROW Access	0	1	1	0	1
Thirtymile Substation ROW Access	0	2	2	0	2
Additional Construction ROW					
Electric Distribution Line	6	0	6	6	0
Off-Site Borrow Area	40	0	40	40	0
Total	**101**	**2,409**	**1,902**	**392**	**1,510**

[a] Construction
[b] Construction plus life of Station
[c] Operations

Project Location (See FEIS Figure 1-1)

If the proposed action will require regular traffic between the site of the proposed action and another site such as a gravel pit or mill, please consider the other site to be part of the project area.

The proposed WPES would be located within the Egan Resource Management Plan (RMP) area. The Egan RMP (BLM, 1984b) identifies several thousand acres of public land for disposal in Steptoe Valley, north of Ely, including land in the area of the proposed Station. Land disposal of the power plant ROW is consistent with the Egan RMP.

The power plant ROW would be located entirely in White Pine County, Nevada, approximately 26 miles south of the White Pine County/Elko County line and approximately 40 miles west of the Nevada/Utah border. Prominent landmarks in the area of the power plant ROW include U.S. Highway 93 (U.S. 93) and the Schell Creek Range (in the Humboldt National Forest) to the east; Duck Creek and the Egan Range to the west; and Goshute Lake to the north. The communities of McGill and Ely are approximately 22 miles and 34 miles south of the power plant ROW, respectively, and Great Basin National Park is 60 miles to the southeast.

The proposed and alternative actions would include a water supply system, temporary distribution lines, a rail spur (approximately 11,000 linear feet of track). The proposed water supply system would extend 13 miles north from the proposed power plant ROW. The alternative water supply system would extend 8 miles south from the alternative power plant ROW. An approximately 2-acre ROW would be temporarily be used for the staging area for placement of materials and equipment during construction. An access road would be located along the water pipeline and electrical distribution line for maintenance purposes and to provide access to each well site. Roads would typically be 10 feet wide.

The electrical transmission facilities for the project would consist of overhead 500-kV (3) and 345-kV (2) electric transmission lines and two electric substations. The first 500-kV line would require a 200-foot ROW and would be approximately 32 miles long, running from Duck Creek to Thirtymile Substation. The project includes two approximately 2.5 miles long, 200-foot wide, 500-kV transmission lines to interconnect the planned SWIP 500-kV transmission lines to the Duck Creek Substation. Two 0.2 mile long, 345-kV lines with 160-foot ROWs would interconnect the Falcon-Gonder 345-kV transmission line to Thirtymile Substation.

The Duck Creek Substation would be located adjacent to and immediately south of the power plant ROW. The Thirtymile Substation would be located in Section 19, Township 18 North, Range 61 East.

A 1.3-mile long rail spur would be constructed from the existing Nevada Northern Railway (NNR) to a rail loop that would be constructed on the proposed power plant ROW. A single span or simple 3-span trestle bridge would be used to cross Duck Creek. These bridge types were chosen to minimize impacts to wetland communities and maintain surface flows in Duck Creek. The alternative rail spur would be 3 miles long and also be constructed from the existing NNR to a rail loop that would be constructed on the alternative power plant ROW.

One or more borrow areas, via minerals materials sale, would be established to provide earth and rock materials during site preparation and throughout the construction process for concrete and asphalt mixes, road base, lining of dikes, and rock surfaced areas. A temporary ROW for the off-site borrow areas would cover approximately 40 acres within the area identified in Figure 1. A fence, berm, or signs would be established at the borrow area entry to prevent public access. Upon completion of construction the borrow area(s) would be recontoured and reclaimed in accordance with BLM regulations. The borrow pit will be deemed free of noxious weeds by a qualified specialist before it is used.

The Moriah Ranches Seeding Project is a habitat enhancement project that would restore existing pasture to better ecological condition and increase forage for livestock and wildlife. The project would be designed to create a habitat mosaic that provides cover for greater sage-grouse and antelope. The project would be located 16 miles north of McGill and immediately west of U.S. 93.

Neither the minerals material sale area, staging areas, access roads outside of project feature ROWs, or the Moriah Ranches Seeding area were surveyed for noxious weeds because the location of these areas was not defined at the time field surveys were completed. These areas would be included in pre-construction noxious/invasive weed surveys. The following sections discuss the ratings for Factor 1 and Factor 2 of the Risk Assessment. A summary of field data is included as Tables 2 and 3.

Factor 1

A definition of Factor 1 appears in the Attachment below. Factor 1 assesses the likelihood of noxious/invasive weed species spreading to the project area. For this project, the factor rates as **(list rating and score**) at the present time**: Moderate (7)**. This rating was based on the following findings:

Due to the large extent and nature of the project, the White Pine Energy Project has a moderate (7) likelihood of spreading noxious/invasive species throughout the project area, despite the proposed implementation of an integrated weed management plan. This finding is based on the field observations recorded for each project feature in June of 2005. There were two noxious weed species present within the project ROWs. There were additional noxious weed species such as Canada thistle (*Cirsium arvense)* and Scotch thistle (*Onorpodum acanthium*) observed outside of the project ROWs, primarily in Butte Valley along existing access roads. In addition species such as tall whitetop (*Lepidium latifolium),* musk thistle (*Carduus nutans*), Russian knapweed (*Acroptilon repens)*, and spotted knapweed (*Centaurea maculosa)* are known to occur within the general area and may be present along travel routes. Travel to and from the ROWs may increase the spread of noxious weeds without proper mitigation.

The majority of weed infestations observed within the proposed and alternative alignments were concentrated along existing access roads, areas previously burned, overgrazed sections, and disturbed areas such as borrow pits. Therefore, the final integrated weed management plan would need to address mitigation measures and best management practices to minimize spread of noxious/invasive weeds in these travel corridors. Given the extent of weed infestations in some areas, it is likely that despite mitigation, invasive weeds may spread in the project area.

The water pipeline for both the proposed and alternative actions would need to be monitored closely post construction to ensure the re-seeding effort is successful to minimize the risk of spreading noxious/invasive species that exist within or adjacent to the ROW.

For the proposed action, risk of spread is moderate to high within the ROWs for the water pipeline, transmission corridors, and power plant.

For the alternative action the risk of spread of noxious/invasive species is moderate to high throughout all project features.

Factor 2

A definition of Factor 2 appears in Appendix A. Factor 2 assesses the consequences of noxious/invasive weed establishment in the project area. For this project, the factor rates as **(List rating and score)**. This rating was based on the following findings:

A definition of Factor 2 appears in Appendix A. Factor 2 assesses the consequences of noxious/invasive weed establishment in the project area. For this project, the factor rates as **(list rating and score)**: **Moderate (7)**. This rating was based on the following findings:

This rating is based on the current conditions (Tables 2 and 3) within the proposed and alternative project areas and the impacts (total acreage) that would result from construction and operation of the project on the vegetation communities. An increase in the spread of noxious and invasive species as a result of future projects occurring in Steptoe and Butte Valleys would increase the potential for cumulative effects to native plant communities.

Risk Rating:

The Risk Rating is obtained by multiplying Factor 1 by Factor 2. For this project, the Risk Rating is **(score and rating)**: **Moderate (49)**

It is important to note that field surveys were conducted in June of 2005. It is probable that weed densities have changed since this time. As a result this risk assessment can only address conditions as they were in 2005. Pre-construction surveys will capture more accurate and detailed information on noxious/invasive weed occurrence in the project area.

Based on this risk rating, preventative management measures **are** needed for this project. Preventative management measures developed for this project are as follows:

I. Pre-construction surveys for noxious and invasive species would be conducted by qualified specialists. Weed populations will be mapped during surveys using GIS.

II. White Pine Energy Associates (WPEA) would be responsible for monitoring and treating identified weed populations within the designated ROWs for the lifetime of the project. Forms of noxious weed treatment would need to be approved by the BLM's Noxious Weed Coordinator. Herbicide treatments within the project ROWs would be reported to the BLM.

III. WPEA would be responsible for ensuring construction crews clean their vehicles prior to entering and upon leaving construction areas.

IV. Areas where re-seeding would occur would be monitored for up to 5 years to ensure native plants, which have been disturbed during project construction, return to areas of the ROW.

V. Materials (gravel, dirt, seeds, etc.) brought into the project area must originate from a weed free source.

The final EIS will include an integrated pest management plan along with a detailed re-seeding plan which will include treatment and monitoring of noxious/invasive species. A list of Reclamation Best Management Practices is included in the DEIS.

Based on this risk rating, project modifications are/**are not (circle one)** needed for this project. Project modifications developed for this project are as follows.

Weed Risk Assessment completed by: Diana Leiker, EDAW/AECOM

Reviewed by/Date Reviewed: ____________________ ____________

Noxious Weed Coordinator Date

Attachment:

Factor 1

NONE (0): Noxious/invasive weed species not located within or adjacent to the project area. Project activity is not likely to result in the establishment of noxious/invasive weed species in the project area.

LOW (1-3): Noxious/invasive weed species present in areas adjacent to but not within the project area. Project activities can be implemented and prevent the spread of noxious/invasive weeds into the project area.

MODERATE (4-7): Noxious/invasive weed species located immediately adjacent to or within the project area. Project activities are likely to result in some areas becoming infested with noxious weed species even when preventative management actions are followed. Control measures are essential to prevent the spread of noxious/invasive weeds within the project area.

HIGH (7-10): Heavy infestations of noxious/invasive weeds are located within or immediately adjacent to the project area. Project activities, even with preventative management actions, are likely to result in the establishment and spread of noxious/invasive weeds on disturbed sites throughout much of the project area.

Factor 2

Low to Nonexistent (1-3): None. No cumulative effects expected.

MODERATE(4-7) : Possible adverse effects on site and possible expansion of infestation within the project area. Cumulative effects on native plant communities are likely, but limited.

HIGH(7-10) : Obvious adverse effects within the project area and probable expansion of noxious weed infestations to areas outside the project area. Adverse cumulative effects on native plant communities are probable.

Risk Rating

NONE (0): Proceed as planned.

LOW (1-10): Proceed as planned. Initiate control treatment on noxious weed populations that get established in the area.

MODERATE (11-49): Develop preventative management measures for proposed project to reduce the risk of introduction or spread of noxious weeds into the area. Preventative management measures should include modifying the project to include seeding the area to occupy disturbed sites with desirable species. Monitor area for at least 3 consecutive years and provide for control of newly established populations of noxious weeds and follow-up treatment for previously treated infestations.

HIGH (50-100): Project must be modified to reduce risk level through preventative management measures, including seeding with desirable species to occupy disturbed sites and controlling existing infestations of noxious weeds prior to project activity. Project

must provide at least 5 consecutive years of monitoring. Projects must also provide for control of newly established populations of noxious weeds and follow-up treatment for previously treated infestations.

TABLE J-4
Weed Densities for the Proposed Action

Species	Common Name	Noxious or Invasive	Transmission Lines	Water Supply System	Rail Spur	Power Plant Site
Cardaria draba	Hoary Cress	Noxious	—	—	-	-
Bromus tectorum	Cheatgrass	Invasive	Moderate	High	Low to Moderate	High
Descurainia sophia	Flixweed	Invasive	Moderate	Moderate	Low	Moderate
Sisymbrium altissimum	Tumble mustard	Invasive	—	Moderate to High	—	—
Salsola iberica	Russian thistle	Invasive	Moderate to High	High	—	—
Halogeton glomeratus	Halogeton	Invasive	High	Low to Moderate	Moderate	—
Lepidium perfoliatum	Pepperweed	Invasive	Low	—	—	—
Ranunculus testiculatus	Bur buttercup	Invasive	Moderate to High	—	—	—
Convolvulus arvensis	Field bindweed	Invasive	—	—	—	—
Kochia scoparia	American kochia	Invasive	—	—	Low to Moderate	—
Potentilla recta	Sulphur cinquefoil	Noxious	Low	—	—	—
Taraxacum officinale	Common dandelion	Invasive	Low to Moderate	—	—	—
Lactuca serriola	Prickly lettuce	Invasive	—	Low	—	—

TABLE J-5
Weed Densities for the Alternative Action

Species	Common Name	Noxious or Invasive	Transmission Lines	Water Supply System	Rail Spur	Power Plant Site
Cardaria draba	Hoary Cress	Noxious	—	—	Moderate	High
Bromus tectorum	Cheatgrass	Invasive	Moderate	Low to Moderate	High	High
Descurainia sophia	Flixweed	Invasive	Moderate	High	—	High
Sisymbrium altissimum	Tumble mustard	Invasive	—	Low to Moderate	—	—
Salsola iberica	Russian thistle	Invasive	Moderate to High	Moderate	—	—
Halogeton glomeratus	Halogeton	Invasive	High	Low to Moderate	—	—
Lepidium perfoliatum	Pepperweed	Invasive	Low	—	—	—
Ranunculus testiculatus	Bur buttercup	Invasive	Moderate to High	—	—	—
Convolvulus arvensis	Field bindweed	Invasive	—	—	—	—
Kochia scoparia	American kochia	Invasive	—	—	—	—
Potentilla recta	Sulphur cinquefoil	Noxious	Low	—	—	—
Taraxacum officinale	Common dandelion	Invasive	Low to Moderate	—	—	—
Lactuca serriola	Prickly lettuce	Invasive	—	—	—	—

Appendix K

U.S. Fish and Wildlife Service Correspondence

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Ely Field Office
HC 33 Box 33500 (702 No. Industrial Way)
Ely, NV 89301-9408
http://www.nv/blm.gov/Ely

DML 6-12-04

In reply refer to:
2850 (NV-043)

JUN 18 2004

Memorandum

To: Field Supervisor, Reno Fish and Wildlife Office, Reno, Nevada

From: Assistant Field Manager, Nonrenewable Resources, Ely, Nevada

Subject: Request for Species List for the White Pine Energy Power Project

The Ely Field Office of the Nevada Bureau of Land Management would like to request a species list for the White Pine Energy Power Project. The proposed action seeks to construct an electric generating facility on approximately 1,300 acres consisting of a coal fired generating plant including steam generators, steam turbine generators, and air pollution control equipment. Additional related structures and facilities would include access roads, railroad facilities, water supply facilities and pipeline facilities, electrical transmission facilities, impoundments, fuel unloading and storage facilities, solid waste disposal facilities, potable water system, septic system, and parking areas.

The preferred and alternate site, are located north of Ely, Nevada on Highway 93 as shown on the map, legal description and CD sent to the USFWS on June 3, 2004. White Pine Energy's proposal is to avoid sensitive areas as much as possible.

If you have any questions please call Doris Metcalf at (775) 289-1852 or by e-mail at Doris_Metcalf@nv.blm.gov.

Sincerely,

/S/ Jeffrey A. Weeks

Jeffrey A. Weeks
Assistant Field Manager
Nonrenewable Resources

Dmetcalf:dam

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1340 Financial Blvd., Suite 234
Reno, Nevada 89502
Ph: 775-861-6300 ~ Fax: 775-861-6301

TAKE PRIDE IN AMERICA

July 19, 2004
File No. 1-5-04-SP-207

Mr. Jeffrey Weeks
Bureau of Land Management
Ely Field Office
HC 33 Box 33500
702 No. Industrial Way
Ely, Nevada 89301-9408

Dear Mr. Weeks:

Subject: Species List for White Pine Energy Power Project, White Pine County, Nevada

In response to your letter received on June 18, 2004, the following federal listed and candidate species may occur in the White Pine Energy Power Project area:

1. Bald eagle (*Haliaeetus leucocephalus*), threatened
2. Yellow-billed cuckoo (*Coccyzus americanus*) (Western US DPS), candidate

This list fulfills the requirement of the Fish and Wildlife Service (Service) to provide information on listed species pursuant to section 7(c) of the Endangered Species Act of 1973, as amended (Act), for projects that are authorized, funded, or carried out by a Federal agency. Candidate species, like the Western yellow-billed cuckoo, receive no legal protection under the Act. However the Yellow-billed cuckoo is protected under the Migratory Bird Treaty Act (MBTA). Consideration of candidate species during project planning may assist species conservation efforts and may prevent the need for future listing actions.

The Nevada Fish and Wildlife Office no longer provides species of concern lists. Most of these species for which we have concern, are also on the sensitive species list for Nevada maintained by the State of Nevada's Natural Heritage Program (Heritage). Instead of maintaining our own list, we are adopting Heritage's sensitive species list and partnering with them to provide distribution data and information on the conservation needs for sensitive species to agencies or project proponents. The mission of Heritage is to continually evaluate the conservation priorities of native plants, animals, and their habitats, particularly those most vulnerable to extinction or

are in serious decline. Consideration of these sensitive species and exploring management alternatives early in the planning process can provide long-term conservation benefits and avoid future conflicts.

For a list of sensitive species by county, visit Heritage's website at www.heritage.nv.gov. For a specific list of sensitive species that may occur in the project area, you can obtain a data request form from the website or by contacting Heritage at
1550 East College Parkway, Suite 137, Carson City, NV 89706, 775-687-4245. Please indicate on the form that your request is being obtained as part of your coordination with the Service under the Endangered Species Act. During your project analysis, if you obtain new information or data for any Nevada sensitive species, we request that you provide the information to Heritage at the above address. Furthermore, certain species of fish and wildlife are classified as protected by the State of Nevada (see http://www.leg.state.nv.us/NAC/NAC_503.html). Before a person can hunt, take, or possess any parts of wildlife species classified as protected, they must first obtain the appropriate license, permit, or written authorization from the
Nevada Department of Wildlife (visit http://www.ndow.org or call 775-777-2300).

We are concerned that the project may impact the Monte Neva paintbrush (*Castilleja salsuginosa*), species listed as sensitive under the Heritage Program. This species is also listed as critically endangered by the State of Nevada under Nevada Revised Statutes (NRS) 527.260-.300. For this species, no member of its kind may be removed or destroyed at any time by any means except under special permit issued by the State Forester (NRS 527.270). Requests for permits should be directed to the State Forester, Nevada Division of Forestry at 2525 South Carson Street, Carson City, Nevada 89701, (775) 684-2500. It should be noted that many of the plant species on the State's critically endangered list are not federally listed by the Service because of the protection afforded to them under the State law. Consideration of this species during project planning and early coordination with the State is important to assist with species conservation efforts and to prevent the need for Federal listing actions in the future.

We note that the greater sage grouse *(Centrocercus urophasianus)*, a species listed as sensitive under the Heritage Program occurs within White Pine Energy Power Project area. The Western States Sage and Columbian Sharp-tailed Grouse Technical Committee, under direction of the Western Association of Fish and Wildlife Agencies, has developed and published guidelines to manage and protect sage grouse and their habitats in the Wildlife Society Bulletin (Connelly *et al.* 2000). We ask that you consider incorporating these guidelines (available at http://www.sagemap.wr.usgs.gov) as you plan and implement your project. Additionally we request that you follow any pertinent management recommendations for this species contained in the White Pine County Portion (Lincoln/White Pine Planning Area) Sage Grouse Conservation Plan (NDOW 2004).

We also note that the pygmy rabbit (*Brachylagus idahoensis*) could be present within the project areas. As such we are concerned that the project could potentially impact this species which has been petitioned for listing under the Act. Draft survey guidelines have been developed for this

species and are available upon request from the Nevada Fish and Wildlife Office. We encourage you to survey the proposed project areas for pygmy rabbits prior to any ground disturbing activities and to consider the needs of this species as you complete project planning and implementation.

Also based on the Service's conservation responsibilities and management authority for migratory birds under the Migratory Bird Treaty Act (MBTA) of 1918, as amended (16 U.S.C. 703 *et. seq.*), we are concerned about potential impacts the proposed project may have on migratory birds in the area. Given these concerns, we recommend that any land clearing or other surface disturbance associated with proposed actions within the project area be timed to avoid potential destruction of bird nests or young, or birds that breed in the area. Such destruction may be in violation of the MBTA. Under the MBTA, nests (nests with eggs or young) of migratory birds may not be harmed, nor may migratory birds be killed. Therefore, we recommend land clearing be conducted outside the avian breeding season. If this is not feasible, we recommend a qualified biologist survey the area prior to land clearing. If nests are located, or if other evidence of nesting (*i.e.*, mated pairs, territorial defense, carrying nesting material, transporting food) is observed, a protective buffer (the size depending on the habitat requirements of the species) should be delineated and the entire area avoided to prevent destruction or disturbance to nests until they are no longer active.

Because wetlands, springs, or streams are present in the vicinity of the proposed White Pine Energy Power Project area , we ask that you be aware of potential impacts project activities may have on these areas. Discharge of fill material into wetlands or waters of the United States is regulated by the U.S. Army Corps of Engineers (Corps) pursuant to section 404 of the Clean Water Act of 1972, as amended. We recommend you contact the Corps' Regulatory Section [insert 300 Booth Street, Room 2103, Reno, Nevada 89509, (775) 784-5304 or 321 North Mall Drive, Suite L-101, St. George, Utah 84790-7314, (435) 986-3979] regarding the possible need for a permit.

Finally we note that springs occur on or near the proposed project site. These springs are sensitive to a wide variety of activities and may be occupied by rare aquatic organisms (macroinvertebrates) that may be affected by the proposed action. Recent studies have found approximately 100 species of aquatic macroinvertebrates in springs and springbrooks throughout the western United States, including springsnails, caddisflies, beetles, true bugs, and crustaceans. There is concern for these species because some are narrowly distributed and, in many cases, their habitats have become highly degraded. Many springs in Nevada have not yet been surveyed to determine if they are occupied by macroinvertebrates. For those which have been surveyed, gravel substrate, flowing high quality water, and minimal disturbance are believed to be important habitat components to maintain viable populations of these species. As you may be aware, your agency is a signatory to a 1998 multi-party Memorandum of Understanding (MOU) concerning the cooperative effort to conserve springsnails and their habitats in the Great Basin. We ask that you include measures in your project planning and implementation to protect the springs, springsnails and other macroinvertebrates, and coordinate your measures to protect this important habitat with the partners and efforts underway as part of the MOU.

Please reference File No. 1-5-04-SP-207 in future correspondence concerning this species list. If you have any questions regarding this correspondence or require additional information, please contact me or Kevin Kritz at (775) 861-6300.

Sincerely,

Stanley N Wiemeyer

for Robert D. Williams
Field Supervisor

United States Department of the Interior

BUREAU OF LAND MANAGEMENT
Ely Field Office
HC 33 Box 33500 (702 No. Industrial Way)
Ely, Nevada 89301-9408
http://www.nv.blm.gov/ely

TAKE PRIDE® IN AMERICA

In Reply Refer To:
N-78091
2850 (NV-043)

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

USFWS Region 1
Ecological Services
Attn: Stanley Wiemeyer
1340 Financial Blvd. Suite 234
Reno, Nevada 89502

Re: Request for Concurrence of Federally Listed Species and Habitat Concerns, White Pine Energy Station Project, White Pine County, Nevada

Dear Mr. Wiemeyer,

Bureau of Land Management (BLM) requests concurrence from the U.S. Fish and Wildlife Service (the Service) on special status species and habitat concerns in a proposed project area for the White Pine Energy Station Project (the Project) submitted by White Pine Energy Associates (WPEA), the majority of which is to be located on Public Lands in White Pine County, Nevada. Prior correspondence with the Service as well as with the Nevada Department of Wildlife (NDOW) regarding the Project occurred on June 18, 2004. The Service response was received by the BLM on July 19, 2004 (Reference File No. 1-5-04-SP-207). These prior communications provided the focus for gathering initial information used in the review of species of concern in the proposed project area. More than a year and a half has passed since the original correspondence, and this letter is to request an updated list of species and habitats of concern for the White Pine Energy Station Project.

The original proposal from WPEA, described in the June 2004 letter, included the construction of a power plant using water cooling technology and a single electric transmission line within the 200 foot right-of-way (ROW) of the Southwest Intertie Project (SWIP) corridor. Assessment of proposed project impacts has lead to some alterations to the original proposal. As revised in December 2005, the Project now includes construction of a power plant using dry cooling technology, an increased width of the transmission corridor from the power plant to the SWIP ROW from 200 to 500 feet to accommodate as many as three separate electric transmission lines, and a reduction in the length of the water supply system. The power plant and associated features (electric transmission facilities, water supply system, rail spur, and access road) are proposed to be located primarily on public lands managed by the Ely Field Office of BLM as shown on the attached maps.

With proposed construction on public lands managed by BLM, the Project must comply with a host of local, state, and federal regulations including the National Environmental Policy Act (NEPA) and BLM regulations. An Environmental Impact Statement (EIS) is being prepared to analyze the Project and is expected to be in draft form in 2006. The following information provides a brief description of the Project and a summary of the resource analysis that will be more fully addressed in the EIS. To comply with Endangered Species Act (ESA) Section 7 consultation requirements, a Biological Assessment (BA) will also be completed and submitted to the Service for concurrence in 2006.

Project Description

The White Pine Energy Station Project is proposed by WPEA to supply reliable, low-cost electricity in an environmentally responsible manner to meet base load energy needs in Nevada and the western United States beginning in 2010, and to bring economic benefits to White Pine County, Nevada. WPEA is proposing to locate the Project on public lands managed by the BLM.

Environmental setting

The majority of the Project lies within Steptoe Valley just north of the town of McGill, Nevada with a portion also crossing the Egan Mountain Range into Butte Valley directly to the west of Steptoe Valley. The Proposed project area is dominated by sagebrush shrublands and pinyon-juniper woodlands. Topography is characterized by high mountain ranges interspersed with valleys, known as basin and range topography. The community types found within the proposed project area include; sagebrush shrublands, salt desert scrub, pinyon-juniper woodlands, greasewood playa, greasewood dunes, rabbit brush, and wetlands.

The primary hydrologic feature within the proposed project area is Duck Creek. The U.S. Army Corp of Engineers has determined that Duck Creek is not a "jurisdictional waters of the U.S." and therefore will not be subject to regulation under Section 404 of the Clean Water Act. Wetlands associated with Duck Creek provide habitat for resident and migratory species. Numerous natural springs with associated wetlands and riparian communities occur in Steptoe Valley.

Federal Species of Concern

The Service previously listed the following federal species of concern as having the potential to occur within the White Pine Energy Station Project area:

Bald eagle (*Haliaeetus leucocephalus*) – Listed Threatened
Yellow-billed cuckoo (*Coccyzus americanus*) – Candidate

Bald Eagles are known to migrate through Steptoe Valley in the winter and can be found foraging south of the proposed project area, around Basset Lake, and along stretches of Duck Creek. No critical habitat for the bald eagle has been identified within the proposed project area.

The absence of woody riparian habitats within the proposed project area means there is no

suitable breeding habitat for the yellow-billed cuckoos within the proposed project area.

Conclusion

BLM will address potential project impacts to federally listed, proposed, or candidate species in the BA; other species of State and BLM concern mentioned in your previous letter will be addressed in the EIS. To ensure that federal species of concern are appropriately addressed, BLM requests an updated list of species of fish and wildlife species that are of federal concern for the White Pine Energy Station Project. In addition, any additional concerns or recommendations regarding the project would be welcomed.

If you have any questions please call Susan Baughman at (775) 289-1827, or Doris Metcalf at (775) 289-1852.

Sincerely,

Jeffery A. Weeks
Assistant Field Manager
Nonrenewable Resources

Attachment
1) Maps (2)

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Nevada Fish and Wildlife Office
1340 Financial Blvd., Suite 234
Reno, Nevada 89502
Ph: (775) 861-6300 ~ Fax: (775) 861-6301

Bureau of Land Management
MAR 0 8 2006
RECEIVED
Ely, NV

February 23, 2006
File No. 1-5-06-SP-066

Memorandum

To: Field Manager, Bureau of Land Management, Ely Field Office, Ely, Nevada (Attn: J. Weeks)

From: Field Supervisor, Nevada Fish and Wildlife Office, Reno, Nevada

Subject: Updated Species List for White Pine Energy Station Project, White Pine County, Nevada

In response to your letter received on January 31, 2006, the following federally listed species may occur in the White Pine Energy Station Project area:

- Bald eagle (*Haliaeetus leucocephalus*), threatened

This list fulfills the requirement of the Fish and Wildlife Service (Service) to provide information on listed species pursuant to section 7(c) of the Endangered Species Act of 1973, as amended (Act), for projects that are authorized, funded, or carried out by a Federal agency.

The Nevada Fish and Wildlife Office no longer provides species of concern lists. Most of these species for which we have concern are also on the sensitive species list for Nevada maintained by the State of Nevada's Natural Heritage Program (Heritage). Instead of maintaining our own list, we are adopting Heritage's sensitive species list and partnering with them to provide distribution data and information on the conservation needs for sensitive species to agencies or project proponents. The mission of Heritage is to continually evaluate the conservation priorities of native plants, animals, and their habitats, particularly those most vulnerable to extinction or in serious decline. Consideration of these sensitive species and exploring management alternatives early in the planning process can provide long-term conservation benefits and avoid future conflicts.

For a list of sensitive species by county, visit Heritage's website at www.heritage.nv.gov. For a specific list of sensitive species that may occur in the project area, you can obtain a data request form from the website or by contacting Heritage at 901 South Stewart Street, Suite 5002, Carson City, Nevada 89701, 775-684-2900. Please indicate on the form that your request is being obtained as part of your coordination with the Service under the Act. During your project analysis, if you obtain new information or data for any Nevada sensitive species, we request that you provide the information to Heritage at the above address. Furthermore, certain species of fish and wildlife are classified as protected by the State of Nevada (see http://www.leg.state.nv.us/NAC/NAC_503.html). Before a person can hunt, take, or possess any parts of wildlife species classified as protected, they must first obtain the appropriate license, permit, or written authorization from the Nevada Department of Wildlife (visit http://www.ndow.org or call 775-777-2300).

We are concerned that the project may impact the Monte Neva paintbrush (*Castilleja salsuginosa*), a plant species listed as sensitive under the Heritage Program. This species is also listed as critically endangered by the State of Nevada under Nevada Revised Statutes (NRS) 527.260-300. For this species, no member of its kind may be removed or destroyed at any time by any means except under special permit issued by the State Forester (NRS 527.270). Requests for permits should be directed to the State Forester, Nevada Division of Forestry at 2525 South Carson Street, Carson City, Nevada 89701, (775) 684-2500. It should be noted that many of the plant species on the State's critically endangered list are not federally listed by the Service because of the protection afforded to them under the State law. Consideration of this species during project planning and early coordination with the State is important to assist with species conservation efforts and to prevent the need for Federal listing actions in the future.

We are concerned that the proposed project may impact the sage grouse (*Centrocercus urophasianus*), which is a species of heightened concern. The Western States Sage and Columbian Sharp-tailed Grouse Technical Committee, under the direction of the Western Association of Fish and Wildlife Agencies, has developed and published guidelines to manage and protect sage grouse and their habitats in the Wildlife Society Bulletin (Connelly *et al.* 2000). We recommend that these guidelines be used in the planning process to provide further conservation for this species. These guidelines are available at: http://sagemap.wr.usgs.gov/docs/sage_grouse_guidelines.pdf. On a more local level, the Sage Grouse Conservation Plan for Nevada and Portions of Eastern California was completed in June 2004. The Plan is available online at: http://www.ndow.org/wild/sg/plan/index.shtm. We encourage you to adopt all appropriate management guidance from this Plan as you implement your proposed action. Additionally, we request that you follow any pertinent management recommendations for this species contained in the White Pine County Portion (Lincoln/White Pine Planning Area) of the Plan (NDOW 2004).

We are concerned that the project may impact the pygmy rabbit (*Brachylagus idahoensis*). In Nevada, the Bureau of Land Management (BLM) includes this species on their sensitive species list. Also the BLM State Director for Nevada has directed all Field Office staff in Nevada to

make it a priority to address the pygmy rabbit in all of the their upcoming Land Use Plan revisions. On May 20, 2005, the Service published a non-substantial 90-day finding determination on a petition to list the pygmy rabbit as threatened or endangered under the Act. Though the pygmy rabbit is not currently a federally-listed species, we continue to monitor the species' status, and we remain concerned about impacts to pygmy rabbit populations. Draft survey guidelines have been developed for this species and are available upon request from the Nevada Fish and Wildlife Office. We encourage you to survey the proposed project area for pygmy rabbits prior to any ground disturbing activities and to consider the needs of this species as you complete project planning and implementation.

Based on the Service's conservation responsibilities and management authority for migratory birds under the Migratory Bird Treaty Act (MBTA) of 1918, as amended (16 U.S.C. 703 *et seq.*), we are concerned about potential impacts the proposed project may have on migratory birds in the area. Given these concerns, we recommend that any land clearing or other surface disturbance associated with proposed actions within the project area be timed to avoid potential destruction of bird nests or young, or birds that breed in the area. Such destruction may be in violation of the MBTA. Under the MBTA, nests (nests with eggs or young) of migratory birds may not be harmed, nor may migratory birds be killed. Therefore, we recommend land clearing be conducted outside the avian breeding season. If this is not feasible, we recommend a qualified biologist survey the area prior to land clearing. If nests are located, or if other evidence of nesting (*i.e.*, mated pairs, territorial defense, carrying nesting material, transporting food) is observed, a protective buffer (the size depending on the habitat requirements of the species) should be delineated and the entire area avoided to prevent destruction or disturbance to nests until they are no longer active.

Because wetlands, springs, or streams are present in the vicinity of the proposed White Pine Energy Power Project area, we ask that you be aware of potential impacts project activities may have on these areas. Discharge of fill material into wetlands or waters of the United States is regulated by the U.S. Army Corps of Engineers (Corps) pursuant to section 404 of the Clean Water Act of 1972, as amended. We recommend you contact the Corps' Regulatory Section [300 Booth Street, Room 2103, Reno, Nevada 89509, (775) 784-5304] regarding the possible need for a permit.

Finally we note that springs occur on or near the proposed project site. These springs are sensitive to a wide variety of activities and may be occupied by rare aquatic organisms (macroinvertebrates) that may be affected by the proposed action. Recent studies have found approximately 100 species of aquatic macroinvertebrates in springs and springbrooks throughout the western United States, including springsnails, caddisflies, beetles, true bugs, and crustaceans. There is concern for these species because some are narrowly distributed and, in many cases, their habitats have become highly degraded. Many springs in Nevada have not yet been surveyed to determine if they are occupied by macroinvertebrates. For those which have been surveyed, gravel substrate, flowing high quality water, and minimal disturbance are believed to be important habitat components to maintain viable populations of these species. As you may be

aware, your agency is a signatory to a 1998 multi-party Memorandum of Understanding (MOU) concerning the cooperative effort to conserve springsnails and their habitats in the Great Basin. We ask that you include measures in your project planning and implementation to protect the springs, springsnails and other macroinvertebrates, and coordinate your measures to protect this important habitat with the partners and efforts underway as part of the MOU.

Please reference File No. 1-5-06-SP-066 in future correspondence concerning this species list. If you have any questions regarding this correspondence or require additional information, please contact me or Marcy Haworth at (775) 861-6300.

Sincerely,

for Robert D. Williams
Field Supervisor

References

Sage-Grouse Conservation Team. 2004. Greater Sage-Grouse Conservation Plan for Nevada and Eastern California. Nevada Department of Wildlife, Reno, Nevada, 108 pp. plus appendices.

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Nevada Fish and Wildlife Office
1340 Financial Blvd., Suite 234
Reno, Nevada 89502
Ph: (775) 861-6300 ~ Fax: (775) 861-6301

August 29, 2007
File No. BLM 7-14

Memorandum

To: Field Manager, Ely Field Office, Bureau of Land Management, Ely, Nevada (Attn: Jeffrey Weeks)

From: Field Supervisor, Nevada Fish and Wildlife Office, Reno, Nevada

Subject: Request to Conclude Informal Consultation on White Pine Energy Station

The Fish and Wildlife Service (Service) received a Biological Assessment (BA) and request to conclude informal consultation on the White Pine Energy Station project pursuant to Section 7 of the Endangered Species Act, as amended, (Act) on June 20, 2007. The bald eagle was the only species included in the BA. In an e-mail to Paul Podborny of your staff on July 9, 2007, we noted that a final rule to delist the bald eagle was imminent; it had, in fact, been published in the Federal Register that same day. We advised that we postpone our response to your request until after the 30-day comment period had closed (i.e., August 8, 2007) so that we could be consistent with the regulatory framework in place at the time the Final Environmental Impact Statement (FEIS) and Record of Decision for the White Pine Energy Station are released.

Since the bald eagle is no longer protected under the Act, no consultation is required. The Service will continue, however, to protect the bald eagle under the authority of the Bald and Golden Eagle Protection Act (BGEPA) and the Migratory Bird Treaty Act (MBTA). Both of these laws prohibit killing, selling, or otherwise harming eagles, their nests, or their eggs. The Service has published National Bald Eagle Management Guidelines which we provided to your staff in an e-mail dated July 19, 2007; these guidelines and other information on the bald eagle, including a draft post-delisting monitoring plan, are available at http://www.fws.gov/migratorybirds/baldeagle.htm. Although the emphasis of the national management guidelines is on protection of nests, there are also recommendations on protecting communal roosts and foraging areas. Since there are no nests or communal roosts in the vicinity of the project, the only relevant guideline is the one to minimize disturbances in the vicinity of

foraging areas. We recommend that the FEIS include a commitment to abide by our national management guidelines under the BGEPA.

The Service is in the process of establishing a permit program under the BGEPA that would authorize limited take of bald and golden eagles consistent with the purpose and goal of the BGEPA. Coverage provided by any take that has been authorized under any existing Biological Opinions will remain in effect until new regulations have been promulgated under the BGEPA.

Although the bald eagle is no longer listed by the federal government, it is important to note that it remains protected under State of Nevada statutes. Therefore, we recommend that you contact the Nevada Department of Wildlife to ensure that you are in compliance with Nevada laws and regulations regarding the bald eagle.

If you have any questions regarding the information provided in this memo, please contact me or Steve Caicco of my staff at 775-631-6300. Specific requests for information about the bald eagle should be directed to Steve Abele on our staff.

Jadye E. Brown
For Robert D. Williams

cc:
Program Lead: Fish, Wildlife, and T&E, Nevada State Office, Bureau of Land Management, Reno, Nevada
Assistant Field Supervisor, Southern Nevada Fish and Wildlife Office, U.S. Fish and Wildlife, Las Vegas, Nevada

Appendix L

Cumulative Analysis for Air Quality

Report

Cumulative Analysis for Air Quality

Prepared for

U.S. Bureau of Land Management

Ely Field Office, Nevada

Contents

1.0 Cumulative Air Quality Analysis

This report describes the NEPA cumulative air impacts predicted for the area of the Proposed Action. NEPA cumulative air impacts differ slightly from PSD cumulative air impacts in that they are evaluated as those resulting from existing facilities, the Proposed Action, and reasonably expected future actions. PSD cumulative air impacts result only from the existing facilities and the Proposed Action (impacts from reasonably expected future actions are not evaluated in a PSD cumulative analysis).

In order to prevent confusion, "PSD" was included as appropriate in the use of these terms in order to discriminate between the two rules (for example, PSD cumulative). If the term is not preceded by PSD than it is to be assumed to be used in the context of NEPA.

Consistent with EPA's position on cumulative PSD modeling (see 72 FR 31390, June 6, 2007), all NEPA cumulative modeling analyses presented below are based on the maximum emission rates for each source during normal operation (for example, 100 percent load operation for power plants) to produce a representative picture of the degree of change in short-term pollution concentrations over time. Emissions associated with infrequent, episodic events such as startups or shutdowns were not evaluated in the cumulative analyses since modeling such events would not be expected to produce results representative of the concentrations that would occur at any given location over time.

2.0 Existing Air Quality

2.1 Introduction

The available air quality data at the proposed White Pine Energy Station (WPES) site are provided to establish the background levels against which changes in air quality are evaluated. During the air quality permitting process, the Nevada Division of Environmental Protection—Bureau of Air Pollution Control (NDEP-BAPC) required White Pine Energy Associates (WPEA) to monitor the ambient air at the proposed site location for 1 full year for air pollutants including nitrogen dioxide (NO_2), particulate matter (PM_{10}), and sulfur dioxide (SO_2). Table 1 shows the existing background air pollution levels measured onsite, along with the latest available air quality monitoring information for the vicinity of the proposed site for lead, and ozone (O_3).

TABLE 1
Summary of Measured Ambient Background Concentrations

Pollutant	Averaging Period	Background Concentration (µg/m^3)
NO_2	Annual	1.9
O_3	8-hour [a]	145
Lead	Quarterly [b]	0.07
SO_2	Annual	2.7
	24-hour	8.0
	3-hour	42.6
PM_{10}	Annual	10
	24-hour	30

Notes:
[a] Based on most recent 3 years of monitoring at Great Basin National Park.
[b] Based on monitoring at Lehman Cave at Great Basin National Park.

2.2 Air Quality Metrics

The cumulative analysis includes evaluations of the predicted air quality impacts with respect to the metrics described in the following text.

2.2.1 NAAQS

The National Ambient Air Quality Standards (NAAQS) are ambient air quality standards established to protect public health and the environment. Additionally, Nevada Ambient Air Quality Standards in NAC 445B.22097(1), which are equivalent to the National Ambient Air Quality Standards, are applicable. For simplicity, both the Nevada and the National

Ambient Air Quality Standards are referred to as the "NAAQS." The Clean Air Act established the following two types of NAAQS:

- Primary standards that set limits to protect public health, including the health of sensitive populations such as asthmatics, children, and the elderly
- Secondary standards that set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings.

The NAAQS are the maximum allowable concentrations of "criteria pollutants" in the ambient air (areas external to buildings and accessible to the general public). The criteria pollutants include carbon monoxide (CO), lead, NO_2, PM_{10}, $PM_{2.5}$, O_3, and SO_2. Air quality modeling analyses for demonstrating compliance with the NAAQS take into account the air emissions sources in the area and the background concentration levels existing in the area. In this way, a NAAQS demonstration evaluates pollutant concentrations caused by both existing facilities and planned future facilities in the area. Table 2 lists the NAAQS for each pollutant.

TABLE 2
Listing of the NAAQS

Pollutant	Averaging Period	Primary NAAQS ($\mu g/m^3$)	Secondary NAAQS ($\mu g/m^3$)
CO	8-hour [a]	10,000	—
	1-hour [a]	40,000	—
NO_2	Annual (Arithmetic Mean)	100	same as primary
O_3	8-hour [e]	160	same as primary
Lead	Quarterly Average	1.5	same as primary
PM_{10}	Annual [b]	50	—
	24-hour [a]	150	—
$PM_{2.5}$	Annual [c]	15.0	same as primary
	24-hour [d]	35	—
SO_2	Annual	80	—
	24-hour [a]	365	—
	3-hour [a]	—	1,300

[a] Not to be exceeded more than once per year.
[b] Revoked by EPA in 2006.
[c] Based on 3-year average of weighted annual mean concentrations.
[d] Based on 3-year average of the 98th percentile of 24-hour concentrations.
[e] Based on 3-year average of the 4th-highest daily maximum 8-hour average.

It should be noted that the NAAQS analysis summarized in the April 2007 DEIS is consistent with the EPA's procedures for demonstrating that a source will not cause or contribute to a violation of the NAAQS. By evaluating reasonably anticipated future projects that submitted air permit applications after the date of the air permit application for the WPES, this cumulative impact analysis goes beyond the requirements for demonstrating compliance with the NAAQS. Because additional emissions are evaluated beyond those required for a NAAQS demonstration, the concentrations presented in this cumulative analysis should be considered conservatively high.

2.2.2 PSD Increment Consumption

The primary purpose of EPA's Prevention of Significant Deterioration (PSD) program is to ensure that significant deterioration of air quality does not occur. The air quality standards set forth by the PSD program are known as the PSD increments. A PSD increment is the maximum allowed increase in pollutant concentration above a baseline concentration in a given area. This prevents a source from consuming available air quality right up to the NAAQS. The PSD increments and the NAAQS work together to ensure that air quality is protected in all areas. The changes in pollutant concentration allowed by the PSD increments are much smaller than the NAAQS; therefore, in areas where existing air quality is good, the PSD increments ensure that air pollution levels never approach the NAAQS, which represent the maximum acceptable pollution levels. PSD increments have been established for NO_2, PM_{10}, and SO_2. Applicants applying for a PSD air permit, such as the WPES, are required to demonstrate that their proposed emissions will not cause or contribute to a violation of the PSD increments.

The PSD air permitting program establishes two separate sets of PSD Increments. Class I increments apply to certain areas designated as Class I areas. Class II increments apply elsewhere. A Class III area designation also exists, but no such area has been designated. The Class I areas within 300 kilometers (km) of the Proposed Action are Zion National Park in Southwest Utah and Jarbidge Wilderness Area in Northern Nevada. All other areas are designated as Class II areas. The Class I and Class II PSD increments are listed in Table 3.

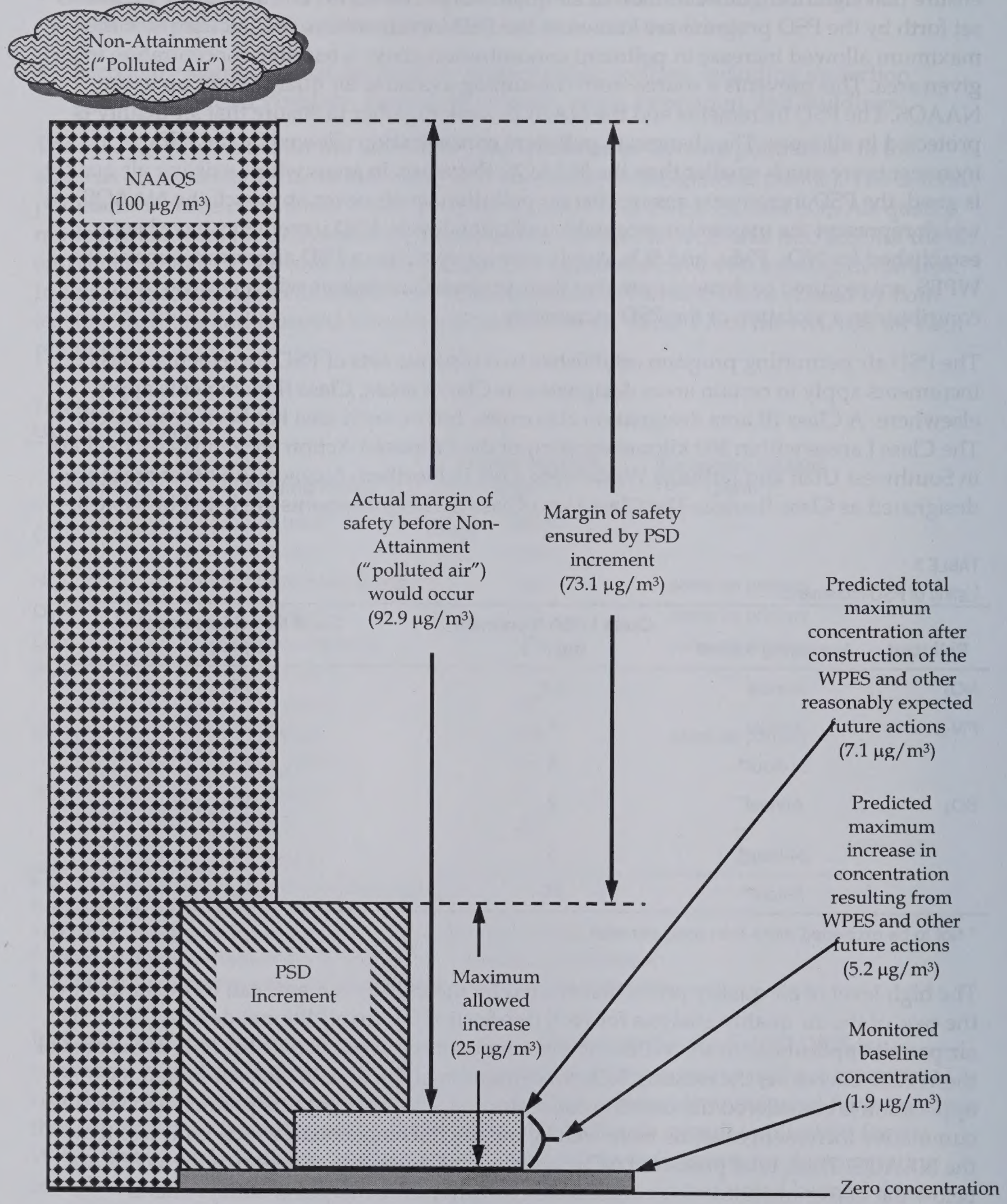
TABLE 3
Listing of PSD Increments

Pollutant	Averaging Period	Class I PSD Increment ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
NO_2	Annual	2.5	25
PM_{10}	Annual	4	17
	24-hour*	8	30
SO_2	Annual	2	20
	24-hour*	5	91
	3-hour*	25	512

* Not to be exceeded more than once per year.

The high level of air quality protection offered by the PSD increments can be illustrated by the case of the air quality analysis for NO_2 (see Section 3.0 for additional details). The PSD air permit application for the WPES set the minor source baseline date for NO_2 in the area of the WPES. Therefore, the existing NO_2 concentration at the time WPEA submitted its application is considered the baseline concentration. The NO_2 impacts predicted in the cumulative increment analysis were well below the PSD increment, which is far less than the NAAQS. Thus, total predicted NO_2 concentrations after construction of the WPES are below the maximum allowable concentrations with a wide margin of safety. This is illustrated in Figure 1.

Figure 1 – Cumulative Air Quality Impacts for NO_2



Finally, it should be noted that the PSD Increment analysis summarized in the April 2007 DEIS is consistent with EPA's procedures for demonstrating that a source will not cause or contribute to a violation of a PSD increment. By evaluating reasonably anticipated future projects that submitted air permit applications after the date of the air permit application for the WPES, this cumulative impact analysis goes beyond the requirements for demonstrating compliance with the PSD increments. Because additional emissions are evaluated beyond those required for a PSD increment demonstration, the concentrations presented in this cumulative analysis should be considered conservatively high.

2.2.3 Visibility

Visibility in an area can be affected by natural or human-caused emissions. The major natural contributor is relative humidity or precipitation (rain or show). Air emissions from power plants and other industry, including sulfur oxides, nitrogen compounds, and particulates, have the potential to create visibility obscuration.

While there are no quantitative limits on visibility obscuration, visibility in Class I areas is protected by the PSD air permitting program, in which the Federal Land Managers, in consultation with the permitting agency, determine whether a new source would have an adverse impact on visibility. Guidance on evaluating visibility impacts in Class I areas was developed by the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) and is called the FLAG Phase I report (December 2000). Visibility is also protected in Class II areas (the remaining areas in the region not designated as Class I) by the secondary NAAQS.

2.2.4 Sulfur and Nitrogen Deposition

Sulfur and nitrogen compounds present in the atmosphere can be deposited on the surface during periods of precipitation (wet deposition) or during periods when no precipitation is present (dry deposition). Depending on the rates of deposition and the sensitivity of a given ecosystem, deposition may have no impact, or deposition may have negative environmental impacts. Sulfur and nitrogen deposited in aquatic ecosystems (such as lakes) have the potential to cause acidification in bodies of water that are not sufficiently buffered. Also in aquatic ecosystems, excess nitrogen may cause changes in algal species composition and abundance, resulting in changes to food web dynamics. Nitrogen may cause eutrophication, with loss of water clarity and potential loss of dissolved oxygen. In terrestrial ecosystems, excess nitrogen may affect soil nutrient cycling and plant community structure and function. For example, nitrogen may favor invasive plant species over native plants.

While there are no quantitative limits on sulfur and nitrogen deposition, air quality related values (AQRVs) in Class I areas (including sulfur and nitrogen deposition) are regulated under the PSD air permitting program, in which the Federal Land Managers, in consultation with the permitting agency, determine whether a new source would have an adverse impact on AQRVs.

Finally, EPA's nationwide Acid Rain Program has reduced SO_2 emissions and subsequent sulfur deposition significantly in recent years. The program requires reductions in annual SO_2 emissions by 10 million tons below 1980 levels by establishing a permanent cap on the total amount of SO_2 that may be emitted by electric generating units in the contiguous

United States. As of 1995, SO_2 emissions had been reduced by almost 40 percent below their required level at the affected units nationwide. EPA reports that Acid Rain Program sources have reduced annual SO_2 emissions by 41 percent compared to 1980 levels and 35 percent compared to 1990 levels. Because of the SO_2 emissions cap under the Acid Rain Program, the total allowable SO_2 emissions on a nationwide basis will not increase, even as new sources such as the WPES are constructed.

The following text presents the results of the cumulative air quality analysis. For each type of analysis, a discussion of the analysis methodology is included, along with a discussion of the results.

3.0 Cumulative NAAQS Analysis

The following subsections present an analysis of the air emissions from the Proposed Action, existing sources, and reasonably expected future actions with respect to the NAAQS. It should be noted that there is a difference between the cumulative analysis that was included in the PSD Air Application and the cumulative analysis presented in this report.

A PSD cumulative analysis includes the proposed action and other existing sources, whereas NEPA requires the cumulative impact analysis to include both direct and indirect effects of the Proposed Action. These effects can occur at the same time and place or at later in time or farther removed in distance, but are still reasonably foreseeable (40 CFR 1508.8). In order to comply with the intent of NEPA, it was assumed that the indirect effects would include emissions from sources that submitted air permit applications after submittal of the WPES application. Therefore, the results of the cumulative analysis and the comparison to the NAAQS should be considered conservative.

3.1 Methodology

The available data for the cumulative NAAQS analysis are taken from the PSD air permit application submitted to NDEP-BAPC by the Nevada Power Company for the Ely Energy Center (EEC) in October 2007, along with the air permit application for the WPES. The EEC is a 1,500-megawatt (MW) pulverized coal-fired power plant proposed for construction by Sierra Pacific Resources and the Nevada Power Company. The EEC is proposed to be constructed approximately 30 km south of the WPES. The NAAQS analysis for the EEC presents the worst-case predicted ambient concentrations resulting from modeling with a full year of on-site meteorological data. The cumulative NAAQS analysis presented here uses the monitored background concentration data from the WPES site (see Table 1), which is expected to be representative of existing conditions in the area where impacts due to the WPES would be highest. For CO, O_3, and lead, EPA policy did not require the EEC to conduct a cumulative analysis to demonstrate compliance with the NAAQS. A cumulative analysis was not required because the results of the "facility-only" preliminary modeling were below the PSD significance levels, values below which EPA policy concludes that the source would not be expected to cause or contribute to any violation of the NAAQS or PSD increments. Therefore, for CO and lead, this cumulative analysis sums the worst-case "facility-only" impacts from the WPES and the EEC to obtain an estimate of the total ambient impacts in the area. For O_3, the EEC has been added to the O_3 screening analysis for the WPES to obtain an estimate of the total ambient impacts in the area. Detailed information showing the calculation of each cumulative NAAQS impact is provided in Attachment 1. The O_3 analysis is provided in Attachment 2.

3.1.1 Sources Included in Evaluation

The sources considered in the cumulative NAAQS analysis include the WPES, the EEC, and the other existing emission sources within 150 km of the WPES. One additional source at a distance of 155 kilometers was included to ensure that predicted concentrations were conservatively high. Emission rates for the other existing emission sources were provided by NDEP-BAPC in support of the modeling analysis. A complete list of the emission sources considered in the cumulative NAAQS analysis is included in Attachment 3 of this report.

3.1.2 Analysis Area

The analysis area (the area where the air dispersion model calculated ground-level concentrations at discrete "receptors") was a 50-km by 50-km area encompassing the WPES, the EEC, and the surrounding topography. Additionally, 30 receptors were modeled on surrounding mountain peaks to ensure maximum impacts were identified at these elevated locations.

3.2 Results

The results of the cumulative NAAQS analysis are provided in Table 4. Detailed information showing the calculation of each cumulative NAAQS impact is provided in Attachment 1. The values shown in Table 4 take into account the background concentrations measured at the WPES site over a full year in accordance with EPA guidance.

As shown in Table 4, the WPES and the other cumulative emission sources are not expected to cause or contribute to any violation of the NAAQS. Additionally, it is noted that the maximum cumulative impacts listed above are not representative of the entire analysis area. Rather, these impacts represent the maximum concentration occurring at one receptor over the specified averaging period. Average impacts over the entire analysis area would be lower.

TABLE 4
Comparison of Cumulative Impacts to the NAAQS

Pollutant	Averaging Period	Maximum Impact from WPES ($\mu g/m^3$)[a]	Cumulative Maximum Impact Including Background ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
CO	8-hour	88.8	250 [b]	10,000
	1-hour	433	1,081 [b]	40,000
NO_2	Annual	1.4	7.1	100
O_3	8-hour	--[c]	145	160
Lead	Quarterly	0.0009	0.071 [d]	1.5
PM_{10}	Annual	7.4	19.4 [e]	50 [e]
	24-hour	24.8	61.9 [e]	150
SO_2	Annual	2.0	9.6	80
	24-hour	17.4	42.0	365
	3-hour	88.7	219	1,300

[a] Maximum impacts from the "facility-only" significance modeling analysis for the WPES.

[b] Represents maximum CO concentration from WPES plus maximum CO concentration from EEC. Results are considered conservatively high because maximum WPES and EEC impacts are not paired in time and space. No background concentration data is available. The Nevada Ambient Air Quality Standards also include a 8-hour average CO threshold of 7,000 μg/m3 for sites located at elevations greater than 5,000 feet above mean sea level.

[c] As demonstrated in Attachment 2, the O_3 concentration increases resulting from the WPES and the EEC is expected to be negligible. Therefore, the O_3 concentration is not expected to rise above existing background levels.

[d] Represents maximum lead concentration from the WPES plus maximum lead concentration from the EEC. Also includes maximum measured background concentration. Results reflect a monthly averaging period, which is more conservative than the required quarterly average. Additionally, results are considered conservatively high because maximum WPES and EEC impacts are not paired in time and space.

[e] Although the annual PM_{10} standard was revoked in 2006, the annual results are presented for informational purposes. EPA policy dictates that PM_{10} be evaluated as a surrogate for $PM_{2.5}$ until such time as final new source review rules for $PM_{2.5}$ are promulgated.

4.0 PSD Increment Consumption

The following subsections present an analysis of the air emissions from the Proposed Action and reasonably expected future actions with respect to the PSD increments. It should be noted that the PSD Increment analysis submitted with the PSD air permit application for the WPES and summarized in the April 2007 DEIS was conducted in accordance with EPA guidance and demonstrated that the WPES would not cause or contribute to any violation of a PSD increment. The cumulative increment analysis presented below goes beyond the requirements for a PSD increment analysis by evaluating emissions from sources that submitted air permit applications after submittal of the WPES application. Therefore, the results of the cumulative analysis and the comparison to the PSD increments should be considered conservative.

4.1 Methodology

4.1.1 Class I Areas

In the air quality analysis prepared by WPEA in support of its PSD air permit application, impacts from the WPES triggered the need for a cumulative analysis for SO_2 only; thus, consistent with EPA guidance, a cumulative Class I analysis was required for SO_2 only. However, to ensure that the impacts from existing facilities, the Proposed Action, and reasonably expected future actions are evaluated in this cumulative analysis, the maximum hypothetical worst-case increment consumption is calculated as the sum of the individual increment consumption values reported for NO_x, PM_{10}, and SO_2 for each source included in the evaluation. This methodology is highly conservative because it assumes that all the reported increment consumption for the various facilities occurs at the same location at the same time (whereas increment consumption actually occurs as separate in space and time). Detailed information showing the calculation of each cumulative PSD increment impact is provided in Attachment 1.

4.1.2 Class II Areas

The available data for the cumulative PSD increment analysis is taken from the PSD air permit application submitted to NDEP-BAPC by the Nevada Power Company for the EEC in October 2007. The PSD Increment analysis for the EEC presents the worst-case predicted ambient concentrations of NO_x, PM_{10}, and SO_2 resulting from modeling with a full year of on-site meteorological data.

4.1.3 Sources Included in Evaluation

When modeling to demonstrate compliance with the (PSD) increments, all increment consuming sources in addition to the proposed source must be included in the inventory. All post-baseline sources emitting SO_2, NO_2, or PM-10 are considered to consume increment. To determine whether or not an existing source consumes increment it is necessary to know the applicable baseline dates. There are two types of baseline dates:

1) Major Source Baseline Dates
2) Minor Source Baseline Dates

The Major Source Baseline Dates are fixed dates identified in the 1977 Clean Air Act for each of the three pollutants. These are:

SO_2 and PM_{10}—January 6, 1975

NO_2—February 8, 1988

Emissions associated with a modification at a major stationary source consume increment after this date.

The Minor Source Baseline Date is set by the first completed PSD application received by the Air Quality Division for a particular air control region (for example, Nevada planning areas/Hydrographic Areas).

4.1.3.1 Class I Areas

The sources considered in the cumulative increment analysis include the WPES, the EEC, Toquop, Newmont, IPP3, and Nevco-Sevier. Toquop is the 750-MW coal-fired power plant proposed for construction in Lincoln County, Nevada, by Toquop Energy, LLC, an affiliate of Sithe Global Power, LLC. Newmont is the 200-MW coal-fired power plant being constructed in Eureka County, Nevada, by Newmont Nevada Energy Investment, LLC. IPP3 is the 950-MW (gross) coal-fired unit proposed at the Intermountain Power Project (IPP) site near Delta, Utah. Nevco-Sevier refers to the 270-MW coal-fired unit proposed in Sevier County, Utah, by Sevier Power Company. Further, an inventory of more than 40 existing SO_2 emission sources was developed during the preparation of the PSD air permit application for the WPES. Impacts from these existing sources were included in the cumulative Class I increment analysis to ensure the best available data was used. This inventory of existing sources is included in Attachment 3. Pursuant to the Class I modeling protocol agreed upon by the National Park Service and USDA Forest Service in August 2006, this inventory of existing sources includes all PSD major sources inside the WPES Class I modeling domain and all PSD minor sources inside the WPES Class I modeling domain within 50 km of a Class I receptor. Due to commencing operation prior to the January 6, 1975, major source date, Reid Gardner Units #1 and #2 were excluded. Refer to Attachment 3 of this report for additional information.

4.1.3.2 Class II Areas

The emission sources considered in the cumulative PSD increment analysis include the WPES, the EEC, and other existing emission sources provided by NDEP and the Utah Division of Air Quality (UDAQ) within 150 km of the WPES (including one additional

Nevada source at a distance of 155 km). Modeling the surrounding sources out to 150 km is considered conservative since, pursuant to the Class II modeling protocol approved by NDEP-BAPC during preparation of the PSD application for the WPES, only those sources within 50 km of the radius of impact (i.e., sources within 117 km of the WPES) were required to be included in the analysis. All emissions were assumed to be increment-consuming, that is, none of the sources provided by the agencies were screened out of the modeling inventory due to the baseline dates. A complete list of the cumulative Class II emission inventory sources is included in Attachment 3 of this report.

4.1.4 Analysis Area

4.1.4.1 Class I Areas

Consistent with EPA guidelines and the modeling protocol agreed upon by WPEA, National Park Service, and USDA Forest Service, the analysis area includes all Class I receptors at Zion National Park and Jarbidge Wilderness Area within 300 km of the WPES.

4.1.4.2 Class II Areas

The analysis area (the area where the air dispersion model calculated ground-level concentrations at discrete "receptors") was a 50-km by 50-km area encompassing the WPES, the EEC, and the surrounding topography. Additionally, 30 receptors were modeled on surrounding mountain peaks to ensure maximum impacts were identified at these elevated locations.

4.2 Results

The results of the cumulative PSD increment analysis for the Class I and Class II areas described above are provided in Tables 5 and 6.

As shown in Tables 5 and 6, the WPES and the other cumulative emission sources are not expected to cause or contribute to any violation of the PSD increments. Thus, the area is not expected to experience significant deterioration in air quality, and construction of the WPES, along with construction of the other proposed sources in the region, would allow for future growth in the area. It should also be noted that increment consumption is both spatial and temporal. Each impact listed above is a maximum occurring at one particular place during one particular time; therefore, maximum impacts are not representative of the average air quality over the analysis area. For example, the maximum WPES-only and cumulative PM_{10} impacts occur at the fence lines of the WPES and the EEC, respectively, and these maximums do not overlap (they do not occur at the same place or during the same time period). Other industry locating in the area in the future would not likely be located at the fence lines of the WPES and EEC where concentrations from the new industry would be more likely to overlap with high predicted concentrations from the WPES and the EEC.

TABLE 5
Comparison of Cumulative Impacts to the Class I PSD Increments

Class I Area	Pollutant	Averaging Period	Predicted Impact from WPES (µg/m^3) [a]	Cumulative Maximum Impact (µg/m^3) [b]	PSD Increment (µg/m^3)
Zion	NO_2	Annual	0.002	0.02	2.5
	PM_{10}	Annual	0.0005	0.02	4
		24-hour	0.02	0.31	8
	SO_2	Annual	0.007	0.04	2
		24-hour	0.18	1.34	5
		3-hour	1.11	7.61	25
Jarbidge	NO_2	Annual	0.004	0.01	2.5
	PM_{10}	Annual	0.001	0.02	4
		24-hour	0.04	0.36	8
	SO_2	Annual	0.02	0.03	2
		24-hour	0.44	1.54	5
		3-hour	1.70	4.90	25

[a] Maximum impacts from the "facility-only" modeling analysis for the WPES.

[b] Represents the sum of the individual increment consumption for the sources included in the analysis (see Section 3.1.1 above for a list of these sources).

TABLE 6
Comparison of Cumulative Impacts to the Class II PSD Increments

Pollutant	Averaging Period	Predicted Impact from WPES (µg/m^3) [a]	Cumulative Maximum Impact (µg/m^3) [b]	PSD Increment (µg/m^3)
NO_2	Annual	1.4	5.2	25
PM_{10}	Annual	7.4	9.4	17
	24-hour	24.8	25.8	30
SO_2	Annual	2.0	6.9	20
	24-hour	17.4	27.4	91
	3-hour	88.7	94.4	512

[a] Maximum impacts from the "facility-only" modeling analysis for the WPES.

[b] Represents the sum of the individual increment consumption for the sources included in the analysis (see Section 3.1.1 above for a list of these sources).

5.0 Visibility

The following subsections present an analysis of the predicted visibility obscuration resulting from the Proposed Action and the reasonably expected future actions. A study that was performed by the National Park Service as part of a response to the Ely Energy Center (EEC) Air Quality Permit has also been included below (Section 5.3).

5.1 Methodology

The individual visibility analyses that were conducted for the Proposed Action and the reasonably expected future actions pursuant to their respective PSD permitting processes represent the best available data for assessing cumulative visibility impacts in the area. The predicted visibility impacts for the various sources are summarized in Section 5.2. Considered collectively, these impacts provide an indication of the visibility impacts that would be expected in the region after construction of the Proposed Action and the reasonably expected future actions.

5.1.1 Sources Included in Evaluation

The sources considered in the evaluation are the WPES, the EEC, Toquop, Newmont, IPP3, and Nevco-Sevier.

5.1.2 Analysis Area

The visibility analysis for the WPES included all Class I receptors at Zion and Jarbidge within 300 km of the WPES. The visibility results listed for the other reasonably expected future actions may apply to additional receptors at Zion greater than 300 km away from the WPES. Additionally, the best available data is provided for Ruby Lake National Wildlife Refuge (Ruby Lake) and Great Basin National Park (Great Basin), which were identified as areas of interest by National Park Service during preparation of the PSD air permit application for the WPES.

5.2 Results

Tables 7, 8, 9, and 10 show the visibility impacts predicted for the Proposed Action and each of the reasonably expected future actions. The predicted visibility impacts are compared against the thresholds of 5 percent (a "just noticeable" change in most landscapes) and 10 percent (a "small but perceptible" change under many conditions). It should be noted that the changes in visibility are calculated relative to estimated natural background conditions. Changes in visibility relative to current levels would actually be lower than presented in the tables because these areas currently experience levels of human-caused visibility impairment on certain days and because the natural background conditions do not include the visibility impacts of wildfire.

TABLE 7
Predicted Visibility Impacts at Jarbidge Wilderness Area

Area	Reasonably Expected Future Actions	Number of Days >5%	Number of Days >10%	Notes
Jarbidge	WPES	15	8	Worst-case year: 2001
	EEC	16	7	Worst-case year: 2004
	Toquop	--	--	N/A: >300 km away
	Newmont	0	0	Worst-case year: 1990
	IPP3	--	--	N/A: >300 km away
	Nevco-Sevier	--	--	N/A: >300 km away

TABLE 8
Predicted Visibility Impacts at Zion National Park

Area	Reasonably Expected Future Actions	Number of Days >5%	Number of Days >10%	Notes
Zion	WPES	2	1	Worst-case year: 1996
	EEC	7	3	Worst-case year: 2004
	Toquop	0	0	Worst-case year: 2003
	Newmont	--	--	N/A: >300 km away
	IPP3	0	0	Modeled year: 1996 (only year modeled)
	Nevco-Sevier	0	0	Modeled year: 1999 (only year modeled)

TABLE 9
Predicted Visibility Impacts at Great Basin National Park

Area	Reasonably Expected Future Actions	Number of Days >5%	Number of Days >10%	Notes
Great Basin	WPES	52	22	Worst-case year: 2002
	EEC	82	45	Worst-case year: 2002
	Toquop	--	--	N/A: not included in Toquop PSD app
	Newmont	--	--	N/A: not included in Newmont PSD app
	IPP3	1	0	Modeled year: 1996 (only year modeled)
	Nevco-Sevier	--	--	N/A: not included in N-S PSD app

TABLE 10
Predicted Visibility Impacts at Ruby Lake National Wildlife Refuge

Area	Reasonably Expected Future Actions	Number of Days >5%	Number of Days >10%	Notes
Ruby Lake	WPES	11	4	Worst-case year: 2001
	EEC	22	16	Worst-case year: 2004
	Toquop	--	--	N/A: not included in Toquop PSD app
	Newmont	--	--	N/A: not included in Newmont PSD app
	IPP3	--	--	N/A: not included in IPP3 PSD app
	Nevco-Sevier	--	--	N/A: >300 km away

The tables above provide an indication of the visibility impacts that are predicted for each area associated with each emissions source. The visibility impacts listed above reflect the "worst-case year" among the available years of modeling results for each facility, where the worst-case year is considered to be the year with the highest number of predicted days with impacts above 10 percent. The predicted visibility impacts on the various areas are not necessarily additive because the values shown are worst-case values (which occur at different locations and during different days). However, some plume overlap and resulting visibility impacts could possibly occur, depending on the meteorology in the region for a given day or series of days.

The visibility impacts presented above should be considered as conservative estimates because of the presence of natural visibility obscuration overlapping with the modeled visibility impacts on certain days. Natural visibility obscuration is associated with periods of rainfall and snow. During such periods, the model may predict visibility impairment from the modeled human sources that would not actually be observable at the modeled location because of the natural impairment resulting from the precipitation.

For each analysis area, if it is assumed that the days of predicted perceptible visibility changes associated with each source did not overlap (that is, each day with a perceptible visibility change modeled for any source contributes one day with a perceptible visibility change to the cumulative evaluation), which is an extremely conservative assumption (because the weather conditions that would maximize visibility impacts from some sources would cause impacts from other sources to be nonexistent, and because the "worst case year" for the various sources would likely be different years), and assuming it would not be raining or snowing on any of the days of predicted visibility impacts (also very conservative), there could be "just noticeable" or perceptible cumulative visibility impacts on the various receptors as follows: Jarbidge Wilderness Area—31 out of 365 days; Zion National Park—9 out of 365 days; Great Basin National Park—135 out of 365 days; Ruby Lake National Wildlife Refuge—33 out of 365 days. Due to the highly conservative nature of the assumptions used for this assessment, the actual number of days when perceptible cumulative visibility impacts would occur would be considerably lower than these figures.

Because there are no quantitative limits on visibility impacts, no regulatory thresholds are available for direct comparison with the predicted visibility impacts; however, the secondary NAAQS are set to protect against decreased visibility. As discussed in Section 3.2, the cumulative impacts are not expected to cause or contribute to any exceedance of the NAAQS; therefore, impacts from the cumulative emission sources are less than the applicable quantitative limits established to protect against decreased visibility.

5.3 National Park Service Study

During the recent PSD air permit public comment period for the EEC (another proposed PC-fired power generation facility in White Pine County), the National Park Service, as part of their comments, conducted a visibility analysis estimating the combined visibility impacts that would result from the WPES and the EEC when considered together. The National Park Service submitted the results of this analysis to NDEP-BAPC (January 9, 2008) and made the results available to the public at http://www.nps.gov/grba/parknews (under *Ely Energy Center Comment Letter & Impact Technical Report* and *Ely Energy Center haze impacts black background)*. Although the National Park Service combined (WPES + EEC) visibility analysis utilized an emissions speciation different from the one agreed upon by the Park Service and WPEA during the air permitting process for the WPES, the results of the National Park Service analysis are comparable to the cumulative visibility results presented in the previous text and are summarized in Table 11 below.

TABLE 11
National Park Service Predicted Visibility Impacts Due to the EEC and WPES Combined

National Park:	Great Basin		Zion	
Year Modeled:	**2002**	**2004**	**2002**	**2004**
Number of Days >5%	133	105	17	12
Number of Days >10%	85	64	5	8
Maximum % Change	103%	197%	48%	28%

Other tables of data and analyses included in the National Park Service comments on the draft air permit for the EEC[1] are applicable to the EEC alone (that is, the Park Service did not analyze the WPES except in the combined visibility section of the EEC comment letter).

Although the National Park Service states in their comment that *"The predicted impacts on visibility at Great Basin again fall well beyond the range of previous adverse impact determinations made by the FLM, and are within the range of impacts at Zion NP that has previously been considered adverse when attributed to a single source."*, the FLAG guidance is for a Class I areas. Since Great Basin Nation Park is not a Class I area this standard is not applicable.

[1] For example, a photo analysis demonstrating maximum visibility impacts for the EEC, see http://www.nps.gov/grba/parknews/upload/Ely%20Energy%20Center%20haze%20impacts%20black%20background.pdf

6.0 Sulfur and Nitrogen Deposition

The following subsections present an analysis of the predicted sulfur and nitrogen deposition resulting from the Proposed Action and the reasonably expected future actions.

6.1 Methodology

The cumulative deposition analysis considers the monitored levels of deposition that have been measured resulting from existing sources, along with the deposition increase that would be predicted because of the Proposed Action and reasonably expected future actions. The existing monitored levels are shown in Table 12.

TABLE 12
Existing Measured Deposition Levels

Area	Monitored Sulfur Deposition (kg/ha/yr)	Monitored Nitrogen Deposition (kg/ha/yr)	Year Corresponding to Maximum
Jarbidge [a]	0.91	2.0	1993
Zion [b]	2.4	4.7	2001
Great Basin [c]	0.71	2.2	2002
Ruby Lake [d]	0.71	2.2	2002

[a] Per the USDA Forest Service, EPA's CASTNET deposition data from Saval Ranch is representative of Jarbidge. Wet and dry deposition data are available from this site for the years 1990 through 1993.

[b] Per the National Park Service, wet deposition at Bryce Canyon is representative of Zion; dry deposition at Canyonlands National Park is representative of Zion. EPA's CASTNET deposition data is available for these two sites for the years 1996 and 2001 through 2004.

[c] Deposition from EPA's CASTNET deposition monitoring site at Great Basin. Wet and dry deposition is available for the years 1996 through 1998, 2001, 2002, and 2004.

[d] Deposition levels at Great Basin are assumed representative of Ruby Lake.

In the deposition analysis conducted as part of the PSD air permit application for the WPES, only the WPES was required to be included. No single modeling assessment has been conducted that would predict the combined deposition impacts of the Proposed Action and the reasonably expected future actions. However, because of the annual averaging period, the individual predicted deposition levels for the Proposed Action and the reasonably expected future actions can be added together to obtain a reasonable estimate of the deposition increase above current levels that would result from construction of the Proposed Action and the reasonably expected future actions. Calculations of the predicted increases in deposition because of the Proposed Action and reasonably expected future actions are shown in Attachment 1 of this report.

Once the current and future deposition levels are determined, the deposition analysis can proceed based on the site-specific information available for each area. The deposition

analyses rely on published information as available (for Zion) and a conservative, empirically-based screening method (for Jarbidge, Great Basin, and Ruby Lake).

A report by the National Park Service provides information about the sensitivity of Zion to air pollution and acid deposition (Binkley et al., 1997). According to the National Park Service, no signs of air pollution injury have been reported for vegetation in or near Zion. Additionally, the National Park Service states the following with regard to acid deposition at Zion:

> The major water resource in Zion National Park is the Virgin River, cutting through the Zion Narrows. The Virgin River has substantial acid buffering capacity and is unlikely to be affected by acid deposition. The Park also has important freshwater habitats including springs, seeps, creeks and ponds that are relatively undisturbed, and which provide habitat islands for aquatic insects. The southeast side of the Park contains exposed bedrock, with rain-filled depressions called waterpockets, potholes or tinajas. These small water bodies vary in depth from several centimeters to 5 meters, and are usually ephemeral. Gladney et al. (1993) measured [acid neutralization capacities] ANCs as low as 220 μeq/l in potholes in Utah, indicating a moderately high buffering capacity of some of these water bodies. However, this lower bound of ANC is still not at the concern level for effects of acid deposition; water quality monitoring would be needed to determine the seasonal fluctuations in pothole chemistry. Given the similarity of geology between Zion and Capitol Reef National Park (Chapter 8), we expect that the aquatic systems are similarly well-buffered with respect to acid deposition (Binkley et al. 1997).

Based on the information from National Park Service in the previous text, waters at Zion are well-buffered and are not expected to be affected by acid deposition. Therefore, cumulative acid deposition is not expected to be a concern at Zion.

For the areas where site-specific agency analysis was not available (Jarbidge, Great Basin, and Ruby Lake), a conservative screening procedure was used to evaluate the potential for adverse environmental impacts because of acid deposition. The U.S. Forest Service research paper, "Estimating Lake Susceptibility to Acidification Due to Acid Deposition" (Nichols, 1990) (the Paper), provides a procedure for predicting acid deposition effects on aquatic ecosystems. To utilize this procedure, the sensitive aquatic ecosystems must be identified, and the ANC for each sensitive aquatic ecosystem is quantified. The ANC data, along with the total deposition for the area, is used to determine whether the deposition levels in question would be safe for the area (safe levels are considered those that would not lower the ANC below 25 microequivalents per liter, μeq/L, creating the potential for acidification concerns). The Paper uses empirical data for high-elevation western lakes to construct "safe lines" on a plot of deposition vs. ion concentration. Per the Paper, site-specific deposition/ANC data points that fall on the right side of the "safe lines" are not expected to be adversely affected by the corresponding deposition levels.

Aquatic ecosystems with an ANC of 50 μeq/L or less are those generally considered potentially sensitive to the effects of acid deposition. Table 13 shows the baseline measured ANC values for aquatic ecosystems analyzed at Jarbidge, Great Basin, and Ruby Lake.

TABLE 13
Area-Specific Aquatic Ecosystems Analyzed

Area	Aquatic Ecosystem Analyzed	Baseline Acid Neutralization Capacity (μeq/L)
Jarbidge	Emerald Lake [a]	342
Great Basin	Baker Lake [b]	73
Ruby Lake	South Marsh [c]	6,594

[a] High-elevation lake at Jarbidge with documented trout population. Acid neutralization capacity value based on alkalinity measured by the Nevada Division of Wildlife.

[b] Aquatic ecosystem of concern noted by National Park Service. Acid neutralization capacity provided by National Park Service.

[c] Aquatic ecosystem of concern noted by USDA Forest Service. Acid neutralization capacity determined by recent sampling.

As shown in Table 12, none of the aquatic ecosystems being analyzed had a baseline ANC in the range that would be considered potentially sensitive to acid deposition effects (ANC less than or equal to 50 μeq/L); thus, a more detailed acid deposition analysis would not typically be required in order to demonstrate that the predicted impacts would not be harmful. However, to ensure a thorough and conservative evaluation of the potential impacts the screening procedure outlined in the Paper was used to evaluate each ecosystem listed in Table 13. Detailed information showing the screening procedure for each ecosystem is provided in Attachment 4.

6.1.1 Sources Included in Evaluation

The sources considered in the cumulative deposition analysis include all existing sources (through the monitored background levels), along with the sources expected to increase deposition in the region, including the WPES, the EEC, Toquop, Newmont, IPP3, and Nevco-Sevier.

6.1.2 Analysis Area

The deposition analysis for the WPES included all Class I receptors at Zion and Jarbidge within 300 km of the WPES. The deposition increases associated with the other reasonably expected future actions may apply to additional receptors at Zion greater than 300 km away from the WPES. Additionally, the deposition analysis also includes Ruby Lake and Great Basin, which were identified as areas of interest by National Park Service during preparation of WPEA's PSD air permit application.

6.2 Results

The results of the cumulative sulfur deposition analysis are provided in Table 14. Aquatic ecosystems at Zion were determined not to be sensitive to the effects of acid deposition based on information published by the National Park Service (see Section 6.1). For aquatic ecosystems at Jarbidge, Great Basin, and Ruby Lake, the deposition analysis was conducted

in accordance with the USDA Forest Service screening procedure discussed in Section 6.1. The details of the screening analyses are presented in Attachment 4 of this report.

TABLE 14
Summary of Cumulative Sulfur Deposition Analysis

Area	Maximum Monitored Deposition (kg/ha/yr)	Modeled Deposition Increase (kg/ha/yr)	Total Predicted Deposition (kg/ha/yr)	Is Deposition Expected to Cause Adverse Impact? *
Jarbidge	0.91	0.03	0.94	No
Zion	2.72	0.02	2.74	No
Great Basin	0.77	0.14	0.91	No
Ruby Lake	0.71	0.03	0.74	No

* Based on available data and screening analyses. See Section 6.1 and Attachment 4.

As shown in Table 14, the predicted increases in sulfur deposition are considered safe, that is, the predicted deposition levels are not expected to have any adverse effects on aquatic ecosystems at any of the areas. The results of the cumulative nitrogen deposition analysis are provided in Table 15.

TABLE 15
Summary of Cumulative Nitrogen Deposition Analysis

Area	Maximum Monitored Deposition (kg/ha/yr)	Modeled Deposition Increase (kg/ha/yr)	Total Predicted Deposition (kg/ha/yr)	Percent Increase Over Existing	Is Deposition Expected to Cause Adverse Impact? *
Jarbidge	2.0	0.008	2.01	0.45	No
Zion	5.8	0.008	5.81	0.14	No
Great Basin	2.1	0.06	2.16	3.33	No
Ruby Lake	2.2	0.01	2.21	0.45	No

* Based on available data and screening analyses. See Section 6.1 and Attachment 4.

As shown in Table 15, the predicted increases in nitrogen deposition are small percentages of the monitored background levels. Predicted increases in cumulative nitrogen deposition are as follows compared to the monitored background levels: Jarbidge Wilderness Area, 0.45 percent; Zion National Park, 0.14 percent; Great Basin National Park, 3.33 percent; and Ruby Lake National Wildlife Refuge, 2.21 percent. No existing adverse effects associated with nitrogen deposition have been noted at any of the areas analyzed.

Adverse environmental conditions can result when terrestrial nitrogen levels become saturated and nitrogen runoff to surface waters occurs. As discussed in Section 2.2.4 above, conditions associated with excess nitrogen in aquatic ecosystems include changes in algal species composition and abundance and resulting in changes to food web dynamics.

Eutrophication, with loss of water clarity and potential loss of dissolved oxygen, is also associated with excess nitrogen in aquatic ecosystems. However, based on the available information (Fenn et al., 1998; Fenn et al., 2003), none of the potentially-sensitive areas studied are nitrogen-saturated, and the small incremental predicted increases in deposition would not be expected to create saturation conditions since the predicted deposition increases are within the year-to-year variability in the monitored deposition data. Thus, the adverse effects to aquatic ecosystems discussed in the previous text would not be expected to result.

As discussed in Section 2.2.4 above, in terrestrial ecosystems, excess nitrogen may affect soil nutrient cycling and plant community structure and function. For example, nitrogen may favor invasive plant species over native plants. However, based on the available information (Fenn et al., 1998; Fenn et al., 2003), none of the potentially-sensitive areas studied are nitrogen-saturated, and the small incremental predicted increases in deposition would not be expected to create saturation conditions since the predicted deposition increases are within the year-to-year variability in the monitored deposition data. Thus, excess nitrogen levels in terrestrial ecosystems with the associated adverse effects to aquatic ecosystems discussed in the previous text would not be expected to result.

Based on the above information, the predicted cumulative increases in nitrogen deposition are not expected to have any adverse effects on aquatic or terrestrial ecosystems.

Eutrophication [illegible] associated with excess nitrogen [illegible] information (Fenn et al., 1998; Fenn et al., 2003), none of the potentially-sensitive areas studied are nitrogen-saturated, and the small incremental increases in deposition would not be expected to create adverse conditions. Also, the predicted deposition increases are within the year-to-year variability in the deposition data. Thus, the adverse [illegible] to aquatic [illegible] would not be expected to result.

As discussed in Section 7.5 [illegible], deposition of excess nitrogen may affect soil nutrient cycling and plant community structure and function. For example, nitrogen may favor invasive plant species over native plants. However, based on the available information (Fenn et al., 1998; Fenn et al., 2003), none of the [illegible] are nitrogen-saturated, and the small incremental increases in deposition would not be expected to create adverse conditions. Also, the predicted deposition increases are within the year-to-year variability in the deposition data. [illegible] levels in terrestrial ecosystems with [illegible] to aquatic ecosystems.

Based on the above information, the predicted increases in nitrogen and sulfur deposition are not expected to have any adverse effects on aquatic or terrestrial ecosystems.

7.0 Mercury

7.1 Background

As a naturally occurring element, mercury is found in the earth's crust. Mercury can be released to the environment through any mechanism that exposes crustal material to the surface or through geothermal activities such as volcanoes and hot springs. Such mechanisms are both natural and anthropogenic (human-caused) in origin and may include mercury mining and processing (primary mercury production), mining of other metals where mercury is produced as a byproduct (secondary mercury production), coal combustion, forest fires, soil or rock weathering, soil/air interface, and ocean/air interface. Additionally, mercury may be released to the environment through spills of mercury-containing chemicals or through improper disposal of mercury-containing equipment such as thermometers or mercury switches.

Mercury emissions and subsequent deposition rates are a global issue. Approximately one-third of global mercury emissions are natural in origin (for example, from oceans or volcanoes) and are not caused by human activities. EPA estimates that about one-third of U.S. emissions are deposited within the contiguous U.S., and the remainder enters the global cycle (EPA, 2007a). Therefore, mercury deposited in a given area may originate from natural sources, local anthropogenic sources, or other anthropogenic sources comprising the global mercury emissions pool.

Mercury concentrations in the ambient air are very low and are not considered a direct concern (EPA, 2000). The primary concern with mercury is that mercury deposited in water bodies can be converted to a toxic form called methylmercury, which can bioaccumulate in the food chain (particularly in predator fish) and create health concerns for humans and animals. Bioaccumulation of methylmercury in the food chain depends on a myriad of factors, including the amount of mercury deposited from the atmosphere, local non-air releases of mercury, naturally occurring mercury in soils, the physical, biological, and chemical properties of different waterbodies, and the age, size and types of food the predator species consume (EPA, 2007b). Because of the ecosystem-specific nature of mercury fate and transport and the large margins of error inherent in predicting the relevant parameters, it is not possible to accurately quantify the increase in methylmercury bioaccumulation that would result from increased mercury emissions from a given new source or a group of new sources.

According to EPA, methylmercury presents health concerns for fetuses, infants, and children. The primary health effect of methylmercury is impaired neurological development. Methylmercury exposure in the womb, which can result from a mother's consumption of fish or shellfish that contain methylmercury, can adversely affect a baby's growing brain and nervous system. Impacts on cognitive thinking, memory, attention, language, and fine-motor and visual spatial skills have been seen in children exposed to methylmercury in the womb. Recent human biological monitoring by the Centers for Disease Control and Prevention in 1999 and 2000 shows that most people have blood

mercury levels below a level associated with possible health effects. More recent data from the CDC support this general finding (EPA, 2007c).

7.2 Mercury Emissions Trends in Nevada

Mercury is geologically concentrated in regions associated with volcanic activity, high heat flow, and plate tectonic boundaries, and is commonly found associated with gold deposits (Jones and Miller, 2005). All of these conditions exist in Nevada.

Nevada is home to a broad "mercury belt" that consists of numerous mercury deposits scattered throughout several tens of thousands of square kilometers, primarily in western and central Nevada (Gray et al., 1999). Because of the presence of this mercury belt, mercury mining in Nevada has historically been an important industry in the state. The last primary mercury mine (mine where mercury is produced as the primary product) in the U.S. was the McDermitt mine in Northern Nevada, which shut down in 1990 after providing 448 metric tons of mercury in that year (Jones and Miller, 2005). The dominant environmental concern associated with these mercury mines is inorganic mercury in cinnabar ore and elemental mercury remaining at the mine sites that may potentially erode into streams and rivers (Gray et al., 1999).

Additionally, mercury has long been associated with gold mining, and in 2003, more than 80 percent of gold production in the U.S. came from Nevada mines. Historically, mercury was used to extract gold from ore. Currently, mercury is a byproduct of gold production and is sold to companies who may further purify the mercury for sale to customers. Mercury may be released to the environment from several points in the gold production process, such as mining, roasting, activated carbon regeneration, retorting, waste rock dumps, and tailings facilities (Jones and Miller, 2005).

Mining companies in Nevada were first required to report mercury emissions to EPA in 1999. Motivated by the high reported emission rates, EPA Region 9, NDEP, and Nevada mining companies worked together to implement a Voluntary Mercury Reduction Program (VMRP), which ultimately reduced mercury emissions from the mines from a baseline of over 21,000 pounds per year in 2001 to less than 3,800 pounds per year in 2004 (NDEP, 2005). Further statewide mercury emissions reductions are expected in the future due to multiple new regulations in effect, including Nevada's Mercury Rule (CAMR) program, the federal CAMR program (mercury emissions standards under 40 CFR Part 60, Subpart Da), and the Nevada Mercury Air Emissions Control Program (NMCP) for the mining industry. The NMCP will require additional controls and reporting for Nevada's mining industry.

7.3 Existing Mercury Levels in Nevada

No ambient air monitoring for mercury has been conducted at the proposed WPES project site or in White Pine County. Mercury concentrations and dry deposition rates at Gibbs Ranch (approximately 215 kilometers north of the proposed WPES site) were measured in a recent study and are summarized in Table 16.

TABLE 16

Mercury Concentrations and Dry Deposition Rates at Gibbs Ranch (24-Hour Averaging Period) [a]

Month	Elemental Hg (µg/m3)	Oxidized Hg (µg/m3)	Particulate Hg (µg/m3)	Total Hg (µg/m3)	Dry Hg Deposition on Soil (kg/ha/yr)
March 05	0.0022	0.002	0.027	0.031	0.000002
July 05	0.0035	0.012	0.012	0.028	Not measured
August 05	0.0024	0.009	0.012	0.023	-0.000041[b]
October 05	0.0020	0.004	0.003	0.009	0.000019
Maximum:	0.0035	0.012	0.027	0.031	0.000019

[a] Lyman et al., 2007

[b] For August 2005, the measured direction of mercury flux was from the soil to the air.

The Nevada Division of Wildlife (NDOW) monitors for mercury in fish tissue around the state. The most recent available NDOW fish tissue monitoring results for water bodies in White Pine County are provided in Table 17. NDOW's monthly fish consumption limits based on methylmercury content are provided in Table 18.

TABLE 17

Mercury Fish Tissue Test Results from NDOW for 2006*

Water Body	Fish Species	Methylmercury Content (ppm wet)
Bassett Lake	Northern Pike	0.03
	Largemouth Bass	0.02
	Carp	0.03
Comins Lake	Northern Pike	1.20
	Largemouth Bass	1.25
	Rainbow Trout	0.85
Snake Creek	Brown Trout	0.08

Source: NDOW, 2007b

TABLE 18

NDOW Suggested Monthly Fish Consumption Limits*

Methylmercury in Fish Tissue (ppm wet)	Fish Consumption Limit (meals per month)
0 - 0.029	Unrestricted (>16)
>0.029 - 0.059	16
>0.059 - 0.078	12
>0.078 - 0.12	8
>0.12 - 0.23	4
>0.23 - 0.31	3
>0.31 - 0.47	2
>0.47 - 0.94	1
>0.94 - 1.9	0.5
>1.9	None (<0.5)

* Source: NDOW, 2007a

As shown in the tables above, methylmercury levels in fish tissue in White Pine County range from low concentrations corresponding to a suggested consumption limit of 16 or more meals per month for Bassett Lake to comparatively high concentrations corresponding to a suggested consumption limit of 0.5 meal per month for Comins Lake. The relatively high methylmercury levels in fish at Comins Lake have been preliminarily determined by NDOW, EPA, and the Nevada Division of Environmental Protection (NDEP) to be the result of mercury contamination from two abandoned mining sites in the lake's drainage area. An EPA report on this issue is expected to be published in the near future.

7.4 Increases in Mercury Levels due to the WPES

Operation of the WPES is expected to increase the amount of mercury present in the air and water globally by a small, incremental amount.

7.4.1 Ambient Mercury

Assuming that the ambient mercury concentrations measured at Gibbs Ranch (see Table 16) are generally representative of background mercury concentrations in the region, Table 19 below shows the maximum predicted mercury concentration that would result from operation of the WPES.

TABLE 19

Predicted Increase in Ambient Mercury Concentration due to the WPES (Annual Averaging Period)

Existing Total Hg Concentration (µg/m3)[a]	Maximum Hg Increase Due to the WPES (µg/m3)[b]	% Increase Predicted Due to the WPES	Predicted Total Hg Concentration (µg/m3)	EPA Prioritized Chronic Dose-Response Level (µg/m3)[b]
0.031	0.000152	0.5%	0.0312	0.3

[a] Maximum total mercury measured at Gibbs Ranch. See Table 15.
[b] Refer to Table 4.6-8 of the FEIS.

As shown in Table 19, the WPES is predicted to increase the mercury concentration in the ambient air by a maximum of 0.5 percent. The predicted total mercury concentration is still well below EPA's chronic exposure threshold. Additionally, the maximum mercury concentration increase due to the WPES would occur approximately 1 kilometer from the WPES fenceline, to the north of the facility, based on the annual averaging period modeling results from the WPES PSD air permit application.

These results can be extrapolated to provide a conservative estimate of cumulative ambient mercury impacts. Although the other proposed power plants in the region (the EEC, Toquop, Newmont, IPP3, and Nevco-Sevier) did not publish mercury modeling results for the vicinity of the WPES, a conservative estimate of the maximum cumulative increase in mercury concentrations could be derived by assuming that each of the cumulative facilities would increase mercury concentrations by the same amount as the WPES and that the maximum mercury concentrations from all the facilities would coincide at the point of maximum concentration for the WPES. The maximum total concentration would be calculated as follows:

$$
\begin{aligned}
\text{Cumulative Hg} &= \text{Existing Hg} + \text{WPES Hg} + \text{Cumulative Hg} \\
&= \text{Existing Hg} + \text{WPES Hg} + (\text{5 Other Facilities}) \times (\text{WPES Hg}) \\
&= 0.031\ \mu g/m^3 + 0.000152\ \mu g/m^3 + (5) \times (0.000152\ \mu g/m^3) \\
&= 0.0319\ \mu g/m^3
\end{aligned}
$$

Therefore, the maximum cumulative concentration (0.0319 $\mu g/m^3$) would be well below EPA's chronic exposure threshold (0.30 $\mu g/m^3$). Additionally, the maximum cumulative mercury impact (0.0319 $\mu g/m^3$) would be only 3% higher than the existing ambient background mercury concentration (0.0319 $\mu g/m^3$). As noted above, this assumes the ambient mercury concentrations measured at Gibbs Ranch (see Table 15) are representative of average background concentrations in the region.

7.4.2 Mercury Deposition and Bioaccumulation

Based on the currently available methods, increases in mercury deposition and methylmercury bioaccumulation resulting from a single source or a group of individual sources cannot be predicted accurately. For example, mercury deposition rates depend on several factors, including, but not limited to, the speciation of mercury in the atmosphere (the relative proportions of the elemental, oxidized, or particulate forms), the land cover type (for example, water, soil, or vegetation type), terrain, and meteorology (for example, global/regional wind patterns, temperatures, and precipitation). In a recent study of eight mercury models, wet and dry deposition rates were shown to diverge from the actual measured values by +/- 45 percent and +/- 50 percent, respectively (Ryaboshapko et al., 2007). Therefore, current models would not be expected to reliably quantify the increase in deposition rates that would occur because of the small incremental increases in mercury concentration resulting from operation of the WPES or the other cumulative sources.

Even if it were possible to accurately predict the incremental increases in mercury deposition rates, the complex and ecosystem-specific nature of methylmercury formation and bioaccumulation would not allow accurate quantification of the corresponding incremental increases in methylmercury bioaccumulation. As discussed above, bioaccumulation of methylmercury in the food chain depends on a myriad of factors,

including the amount of mercury deposited from the atmosphere, local non-air releases of mercury, naturally occurring mercury in soils, the physical, biological, and chemical properties of different waterbodies, and the age, size and types of food the predator species consume. The margin of uncertainty in predicted bioaccumulation rates that would result from attempting to estimate these various ecosystem-specific parameters would be expected to preclude sufficient resolution to differentiate the effects of small incremental increases in ambient mercury concentration (EPA, 2001). Thus, current models and available methods would not be expected to reliably quantify the increase in methylmercury bioaccumulation that would occur because of the small incremental increases in mercury concentration resulting from operation of the WPES or the other cumulative sources.

Notwithstanding the difficulties noted above in predicting mercury deposition and bioaccumulation rates, it could conservatively be assumed that these parameters would increase proportionally with increases in mercury concentration in the ambient air. That is, for the location of hypothetical peak-case ambient mercury concentration discussed above (the location just to the north of the WPES fenceline where ambient mercury concentrations from the WPES and all the other cumulative sources are assumed to overlap), mercury deposition and bioaccumulation rates could increase by up to 3 percent above the existing values. Note that this estimate is highly conservative, considering the speciation of the mercury emitted from the WPES, the depositional mechanisms for the emitted mercury, and the chemical and biological transformations required for the methylation of mercury in the environment. The actual increases in deposition and subsequent bioaccumulation would be expected to be significantly less than 3 percent even if ambient mercury concentrations were to increase by 3 percent (which is considered a hypothetical peak-case assumption). Because a 3 percent increase in ambient mercury concentrations is a highly conservative estimate (mercury concentrations due to the various facilities would not actually overlap at the locations of maximum concentration), actual increases in deposition and bioaccumulation would be expected to be much less than 3 percent.

8.0 Works Cited

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Attachment 1

Calculation of Cumulative Impacts

Analysis: **NAAQS**
Pollutant: **CO**

Averaging Period	Measured Background (μg/m³)	Facilities Modeled	Modeled Impact (μg/m³)	Source of Modeled Impact Information	Total Impact (μg/m³)	Regulatory Limit (μg/m³)	Notes
1-hour	Not measured	WPES	433	WPEA PSD significance modeling report	1,081	40,000	Total impact includes WPEA and EEC only (no other information available). Results are conservative since impacts are not paired in time or space.
		Ely Energy Center	648	EEC PSD significance modeling report			
8-hour	Not measured	WPES	88.8	WPEA PSD significance modeling report	250	10,000	Total impact includes WPEA and EEC only. Results are conservative since impacts are not paired in time or space.
		Ely Energy Center	161	EEC PSD significance modeling report			

Analysis: NAAQS
Pollutant: Pb

Averaging Period	Measured Background (μg/m³)	Facilities Modeled	Modeled Impact (μg/m³)	Source of Modeled Impact Information	Total Impact (μg/m³)	Regulatory Limit (μg/m³)	Notes
Quarterly	0.07	WPES	0.0009	WPEA PSD significance modeling report	0.071	1.5	Total impact includes WPEA, EEC, and background. Background value is maximum measured at Lehman Cave from 1977 to 1987. Results are conservative since impacts are not paired in time or space.
		Ely Energy Center	0.00059	EEC PSD significance modeling report			

Analysis: NAAQS
Pollutant: NO_2

Averaging Period	Measured Background ($\mu g/m^3$)	Facilities Modeled	Modeled Impact ($\mu g/m^3$)	Source of Modeled Impact Information	Total Impact ($\mu g/m^3$)	Regulatory Limit ($\mu g/m^3$)	Notes
Annual	1.9	WPES, EEC, and other surrounding sources	5.2	EEC PSD full impacts modeling report	7.1	100	Background from on-site monitoring at the WPES site.

Analysis: NAAQS
Pollutant: PM10

Averaging Period	Measured Background ($\mu g/m^3$)	Facilities Modeled	Modeled Impact ($\mu g/m^3$)	Source of Modeled Impact Information	Total Impact ($\mu g/m^3$)	Regulatory Limit ($\mu g/m^3$)	Notes
24-hour	30	WPES, EEC, and other surrounding sources	31.9	EEC PSD full impacts modeling report	61.9	150	Background from on-site monitoring at the WPES site.
Annual	10	WPES, EEC, and other surrounding sources	9.4	EEC PSD full impacts modeling report	19.4	50	Background from on-site monitoring at the WPES site.

Analysis: NAAQS
Pollutant: SO_2

Averaging Period	Measured Background ($\mu g/m^3$)	Facilities Modeled	Modeled Impact ($\mu g/m^3$)	Source of Modeled Impact Information	Total Impact ($\mu g/m^3$)	Regulatory Limit ($\mu g/m^3$)	Notes
3-hour	42.6	WPES, EEC, and other surrounding sources	176	EEC PSD full impacts modeling report	218.6	1,300	Background from on-site monitoring at the WPES site.
24-hour	8	WPES, EEC, and other surrounding sources	34.0	EEC PSD full impacts modeling report	42	365	Background from on-site monitoring at the WPES site.
Annual	2.7	WPES, EEC, and other surrounding sources	6.9	EEC PSD full impacts modeling report	9.6	80	Background from on-site monitoring at the WPES site.

Analysis: Increment
Pollutant: NO2
Area(s): Class II

Averaging Period	Facilities Modeled	Source of Modeled Impact Information	Modeled Impact ($\mu g/m^3$)	Regulatory Limit ($\mu g/m^3$)	Notes
Annual	WPES, EEC, and other surrounding sources	EEC PSD full impacts modeling report	5.2	25	--

Analysis: **Increment**
Pollutant: **PM10**
Area(s): **Class II**

Averaging Period	Facilities Modeled	Source of Modeled Impact Information	Modeled Impact ($\mu g/m^3$)	Regulatory Limit ($\mu g/m^3$)	Notes
24-hour	WPES, EEC, and other surrounding sources	EEC PSD full impacts modeling report	25.8	30	Value reported is highest 2nd-high for comparison to the standard.
Annual	WPES, EEC, and other surrounding sources	EEC PSD full impacts modeling report	9.4	17	--

Analysis: **Increment**
Pollutant: **SO2**
Area(s): **Class II**

Averaging Period	Facilities Modeled	Source of Modeled Impact Information	Modeled Impact ($\mu g/m^3$)	Regulatory Limit ($\mu g/m^3$)	Notes
3-hour	WPES, EEC, and other surrounding sources	EEC PSD full impacts modeling report	94.4	512	Value reported is highest 2nd-high for comparison to the standard.
24-hour	WPES, EEC, and other surrounding sources	EEC PSD full impacts modeling report	27.4	91	Value reported is highest 2nd-high for comparison to the standard.
Annual	WPES, EEC, and other surrounding sources	EEC PSD full impacts modeling report	6.9	20	--

Analysis: Increment
Pollutant: NO2
Area(s): Class I

Class I Area	Averaging Period	Regulatory Limit ($\mu g/m^3$)	Facilities Modeled	Modeled Impact ($\mu g/m^3$)	Source of Modeled Impact Information	Notes
Jarbidge	Annual	2.5	WPES	0.004	WPES PSD app	--
			EEC	0.002	EEC PSD app	--
			Toquop	--	--	N/A: Toquop >300 km away
			Newmont	0.004	Newmont PSD app	--
			IPP3	--	--	N/A: IPP3 >300 km away
			Nevco-Sevier	--	--	N/A: N-S >300 km away
			Total Modeled Impact:	**0.010**		
Zion	Annual	2.5	WPES	0.002	WPES PSD app	--
			EEC	0.001	EEC PSD app	--
			Toquop	0.002	Toquop PSD app	--
			Newmont	--	--	N/A: Newmont >300 km away
			IPP3	0.002	IPP3 PSD app	--
			Nevco-Sevier	0.012	UDAQ eng. review	Worst-case: not specific to Zion
			Total Modeled Impact:	**0.019**		

Analysis: Increment
Pollutant: PM10
Area(s): Class I

Class I Area	Averaging Period	Regulatory Limit ($\mu g/m^3$)	Facilities Modeled	Modeled Impact ($\mu g/m^3$)	Source of Modeled Impact Information	Notes
Jarbidge	24-hour	4	WPES	0.04	WPES PSD app	--
			EEC	0.18	EEC PSD app	--
			Toquop	--	--	N/A: Toquop >300 km away
			Newmont	0.14	Newmont PSD app	--
			IPP3	--	--	N/A: IPP3 >300 km away
			Nevco-Sevier	--	--	N/A: N-S >300 km away
			Total Modeled Impact:	**0.36**		
	Annual	8	WPES	0.001	WPES PSD app	--
			EEC	0.006	EEC PSD app	--
			Toquop	--	--	N/A: Toquop >300 km away
			Newmont	0.010	Newmont PSD app	--
			IPP3	--	--	N/A: IPP3 >300 km away
			Nevco-Sevier	--	--	N/A: N-S >300 km away
			Total Modeled Impact:	**0.017**		
Zion	24-hour	4	WPES	0.02	WPES PSD app	--
			EEC	0.12	EEC PSD app	--
			Toquop	0.09	Toquop PSD app	--
			Newmont	--	--	N/A: Newmont >300 km away
			IPP3	0.04	IPP3 PSD app	--
			Nevco-Sevier	0.05	UDAQ eng. review	Worst-case: not specific to Zion
			Total Modeled Impact:	**0.31**		
	Annual	8	WPES	0.001	WPES PSD app	--
			EEC	0.004	EEC PSD app	--
			Toquop	0.004	Toquop PSD app	--
			Newmont	--	--	N/A: Newmont >300 km away
			IPP3	0.002	IPP3 PSD app	--
			Nevco-Sevier	0.004	UDAQ eng. review	Worst-case: not specific to Zion
			Total Modeled Impact:	**0.015**		

Analysis: Increment
Pollutant: SO2
Area(s): Class I

Class I Area	Averaging Period	Regulatory Limit ($\mu g/m^3$)	Facilities Modeled	Modeled Impact ($\mu g/m^3$)	Source of Modeled Impact Information	Notes
Jarbidge	3-hour	25	WPES	2.02	WPES PSD app	Includes Class I SO2 increment modeling inventory sources - See Attachment 3
			EEC	2.02	EEC PSD app	--
			Toquop	--	--	N/A: Toquop >300 km away
			Newmont	0.86	Newmont PSD app	--
			IPP3	--	--	N/A: IPP3 >300 km away
			Nevco-Sevier	--	--	N/A: N-S >300 km away
			Total Modeled Impact:	**4.90**		
	24-hour	5	WPES	0.95	WPES PSD app	Includes Class I SO2 increment modeling inventory sources - See Attachment 3
			EEC	0.41	EEC PSD app	--
			Toquop	--	--	N/A: Toquop >300 km away
			Newmont	0.18	Newmont PSD app	--
			IPP3	--	--	N/A: IPP3 >300 km away
			Nevco-Sevier	--	--	N/A: N-S >300 km away
			Total Modeled Impact:	**1.54**		
	Annual	2	WPES	0.01	WPES PSD app	--
			EEC	0.01	EEC PSD app	--
			Toquop	--	--	N/A: Toquop >300 km away
			Newmont	0.01	Newmont PSD app	--
			IPP3	--	--	N/A: IPP3 >300 km away
			Nevco-Sevier	--	--	N/A: N-S >300 km away
			Total Modeled Impact:	**0.03**		

Analysis: **Increment**
Pollutant: **SO2**
Area(s): **Class I**

Class I Area	Averaging Period	Regulatory Limit (μg/m³)	Facilities Modeled	Modeled Impact (μg/m³)	Source of Modeled Impact Information	Notes
Zion	3-hour	25	WPES	3.98	WPES PSD app	Includes Class I SO2 increment modeling inventory sources - See Attachment 3
			EEC	1.04	EEC PSD app	--
			Toquop	0.57	Toquop PSD app	--
			Newmont	--	--	N/A: Newmont >300 km away
			IPP3	1.23	IPP3 PSD app	--
			Nevco-Sevier	0.78	UDAQ eng. review	Worst-case: not specific to Zion
			Total Modeled Impact:	**7.61**		
	24-hour	5	WPES	0.66	WPES PSD app	Includes Class I SO2 increment modeling inventory sources - See Attachment 3
			EEC	0.23	EEC PSD app	--
			Toquop	0.12	Toquop PSD app	--
			Newmont	--	--	N/A: Newmont >300 km away
			IPP3	0.18	IPP3 PSD app	--
			Nevco-Sevier	0.14	UDAQ eng. review	Worst-case: not specific to Zion
			Total Modeled Impact:	**1.34**		
	Annual	2	WPES	0.01	WPES PSD app	--
			EEC	0.01	EEC PSD app	--
			Toquop	0.01	Toquop PSD app	--
			Newmont	--	--	N/A: Newmont >300 km away
			IPP3	0.01	IPP3 PSD app	--
			Nevco-Sevier	0.01	UDAQ eng. review	Worst-case: not specific to Zion
			Total Modeled Impact:	**0.04**		

Analysis: Visibility
24-Hour Averaging Period

Area	Reasonably Expected Future Actions	Number of Days >5%	Number of Days >10%	Notes *
Jarbidge	WPES	15	8	Worst-case year: 2001
	EEC	13	8	Worst-case year: 2004
	Toquop	--	--	N/A: >300 km away
	Newmont	0	0	Worst-case year: 1990
	IPP3	--	--	N/A: >300 km away
	Nevco-Sevier	--	--	N/A: >300 km away
Zion	WPES	2	1	Worst-case year: 1996
	EEC	6	3	Worst-case year: 2004
	Toquop	0	0	Worst-case year: 2003
	Newmont	--	--	N/A: >300 km away
	IPP3	0	0	Modeled year: 1996 (only year modeled)
	Nevco-Sevier	0	0	Modeled year: 1999 (only year modeled)
Great Basin	WPES	52	22	Worst-case year: 2002
	EEC	74	38	Worst-case year: 2002
	Toquop	--	--	N/A: not included in Toquop PSD app
	Newmont	--	--	N/A: not included in Newmont PSD app
	IPP3	1	0	Modeled year: 1996 (only year modeled)
	Nevco-Sevier	--	--	N/A: not included in N-S PSD app
Ruby Lake	WPES	11	4	Worst-case year: 2001
	EEC	22	13	Worst-case year: 2004
	Toquop	--	--	N/A: not included in Toquop PSD app
	Newmont	--	--	N/A: not included in Newmont PSD app
	IPP3	--	--	N/A: not included in IPP3 PSD app
	Nevco-Sevier	--	--	N/A: >300 km away

* Worst-case year is the year with the highest number of days above 10% for the area.

Analysis: Sulfur Deposition
Annual Averaging Period

Area	Reasonably Expected Future Actions	Modeled Deposition (kg/ha/yr)	Source of Information for Modeled Increase	Notes
Jarbidge	WPES	0.018	WPES PSD app	Includes both wet and dry deposition.
	EEC	0.006	EEC PSD app	
	Toquop	--	N/A: >300 km away	
	Newmont	0.005	Newmont PSD app	
	IPP3	--	N/A: >300 km away	
	Nevco-Sevier	--	N/A: >300 km away	
	Total Increase:	**0.028**		
Zion	WPES	0.009	WPES PSD app	Includes both wet and dry deposition.
	EEC	0.003	EEC PSD app	
	Toquop	0.005	Toquop PSD app	
	Newmont	--	N/A: >300 km away	
	IPP3	0.004	IPP3 PSD app	
	Nevco-Sevier	0.001	UDAQ eng. review	
	Total Increase:	**0.021**		
Great Basin	WPES	0.054	WPES PSD app	Includes both wet and dry deposition.
	EEC	0.085	EEC PSD app	
	Toquop	--	N/A: not included in Toquop PSD app	
	Newmont	--	N/A: not included in Newmont PSD app	
	IPP3	0.005	IPP3 PSD app	
	Nevco-Sevier	--	N/A: not included in N-S PSD app	
	Total Increase:	**0.144**		
Ruby Lake	WPES	0.014	WPES PSD app	Includes both wet and dry deposition.
	EEC	0.014	EEC PSD app	
	Toquop	--	N/A: not included in Toquop PSD app	
	Newmont	--	N/A: not included in Newmont PSD app	
	IPP3	--	N/A: not included in IPP3 PSD app	
	Nevco-Sevier	--	N/A: >300 km away	
	Total Increase:	**0.028**		

Analysis: Nitrogen Deposition
Annual Averaging Period

Area	Reasonably Expected Future Actions	Modeled Deposition (kg/ha/yr)	Source of Information for Modeled Increase	Notes
Jarbidge	WPES	0.003	WPES PSD app	Includes both wet and dry deposition.
	EEC	0.003	EEC PSD app	
	Toquop	--	N/A: >300 km away	
	Newmont	0.002	Newmont PSD app	
	IPP3	--	N/A: >300 km away	
	Nevco-Sevier	--	N/A: >300 km away	
	Total Increase:	**0.008**		
Zion	WPES	0.002	WPES PSD app	Includes both wet and dry deposition.
	EEC	0.002	EEC PSD app	
	Toquop	0.003	Toquop PSD app	
	Newmont	--	N/A: >300 km away	
	IPP3	0.001	IPP3 PSD app	
	Nevco-Sevier	0.001	UDAQ eng. review	
	Total Increase:	**0.008**		
Great Basin	WPES	0.016	WPES PSD app	Includes both wet and dry deposition.
	EEC	0.042	EEC PSD app	
	Toquop	--	N/A: not included in Toquop PSD app	
	Newmont	--	N/A: not included in Newmont PSD app	
	IPP3	0.002	IPP3 PSD app	
	Nevco-Sevier	--	N/A: not included in N-S PSD app	
	Total Increase:	**0.060**		
Ruby Lake	WPES	0.003	WPES PSD app	Includes both wet and dry deposition.
	EEC	0.006	EEC PSD app	
	Toquop	--	N/A: not included in Toquop PSD app	
	Newmont	--	N/A: not included in Newmont PSD app	
	IPP3	--	N/A: not included in IPP3 PSD app	
	Nevco-Sevier	--	N/A: >300 km away	
	Total Increase:	**0.009**		

Attachment 2

Ozone Analysis

White Pine Energy Station

Cumulative Ozone Analysis

Rigorous analysis of ozone impacts is not possible without access to regional grid modeling, which has not been previously prepared by the agencies for this region. Therefore, a screening assessment method must be used. One common screening method, the Scheffe method, is not applicable because this method is applicable to VOC-dominated point sources only (Scheffe, 09/1998), and the sources in the area (i.e., the WPES and the EEC) are NOX-dominated sources. Since the WPES and EEC are NOX-dominated sources, typical empirical kinetic modeling approach (EKMA) isopleths are used to estimate the cumulative ozone impacts in the area of the WPES and the EEC. The following inputs are needed to estimate impacts using EKMA isopleths:

VOC and NOX Concentrations

The VOC and NOX concentrations of the combined exhaust are calculated from the emission rates and volumetric flows shown in the air permit applications for the WPES and the EEC.

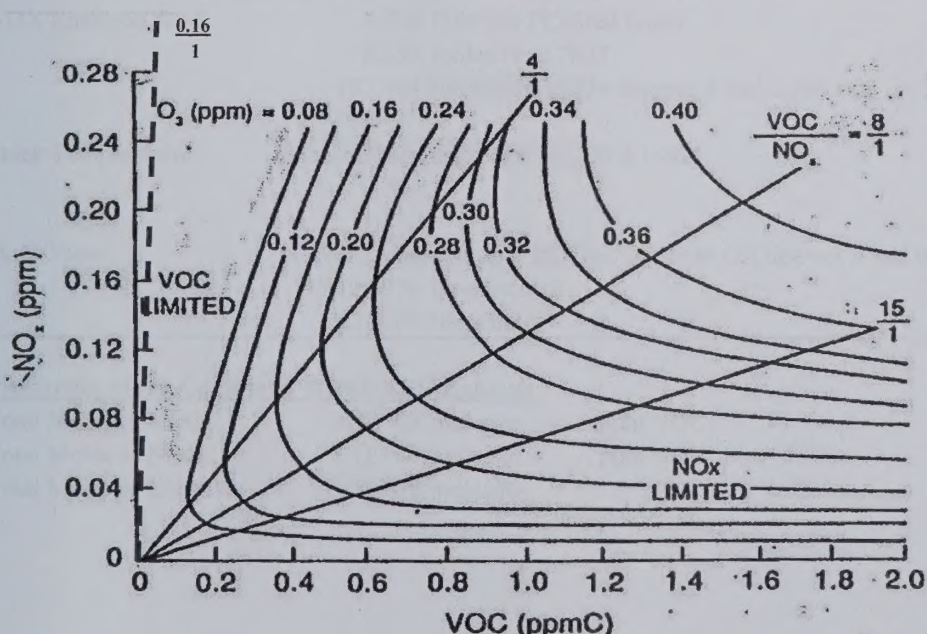
Concentration	
VOC (ppm)	NOX (ppm)
6.00	38.1

VOC-to-NOX Ratio

The VOC-to-NOX ratio is calculated as the ratio of VOC concentration to NOX concentration in the gas. This ratio is used to define a line that would intersect a maximum ozone isopleth on the EKMA chart. The EKMA chart is shown below, with the WPEA VOC-to-NOX ratio indicated by a dashed line.

VOC-to-NOX Ratio: 0.16

Typical EKMA curve. Adapted from Dodge, 1977.



As shown in the chart above, the VOC-to-NOX line for the combined exhaust falls well below the lowest ozone isopleth. Thus, it is concluded that the facilities would have a negligible effect on ambient ozone levels.

White Pine Energy Station

Reference Information for Cumulative Ozone Analysis

The following background information is used in the ozone analysis.

WPES Flow and Emissions Data at 100% Load:

VOC Emission Rate:	18.8	lb/hr per PC-fired boiler
	532	moles/hr as methane
	15,137	liters/hour at 165 degrees F and 0.788 atm
NOX Emission Rate:	365.2	lb/hr per PC-fired boiler
	3,601	moles/hr as NO2
	102,540	liters/hour at 165 degrees F and 0.788 atm
Stack Temperature:	165	degrees F (at 100% load)
	347	K
Stack Flow:	1,509,649	acfm per PC-fired boiler at 165 degrees F and 0.788 atm
	42,748,731	liters/minute
	2.6E+09	liters/hour

EEC Flow and Emissions Data at 100% Load:

VOC Emission Rate:	30.5	lb/hr per PC-fired boiler
	862	moles/hr as methane
	22,935	liters/hour at 124 degrees F and 0.788 atm
NOX Emission Rate:	522.6	lb/hr per PC-fired boiler
	5,153	moles/hr as NO2
	137,104	liters/hour at 124 degrees F and 0.788 atm
Stack Temperature:	124	degrees F (at 100% load)
	324	K
Stack Flow:	3,382,914	acfm per PC-fired boiler at 124 degrees F and 0.788 atm
	95,793,976	liters/minute
	5.7E+09	liters/hour

Properties of the Combined WPES/EEC Exhaust

Total Moles of VOC:	3.3E+03	moles/hr	ppm VOC:	6.0
Total Moles of NOX:	2.1E+04	moles/hr	ppm NOX:	38.1
Total Moles of Exhaust:	5.5E+08	moles/hr		

White Pine Energy Station

Reference Information for Cumulative Ozone Analysis

Additional Reference Data:

Molecular Weights for Compounds of Interest

Compound	Molecular Weight (g/mole)	Notes
VOC	12.0 16.0	As carbon As methane
NOX	46.0	As NO_2

R (ideal gas constant): 0.082057 (L*atm) / (mol*K)

Attachment 3

Modeling Inventory Data

MODELED POINT SOURCE EMISSIONRATES AND STACK PARAMETERS

POINT SOURCES														
									Modeled Emission Rates (g/s)[1]					
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (m)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (meters)	CO	NO_X	Pb	PM_{10}	SO_2	VOC
MSTK1	Unit #1 Boiler	690102	4374813	1889	221.6	324.3	16.80	11.00	109.75	65.85	2.8E-02	21.95	3-hr 87.80 24 -hr 65.85	3.84
MSTK2	Unit #2 Boiler	690114	4374813	1889	221.6	324.3	16.80	11.00	109.75	65.85	2.8E-02	21.95	3-hr 87.80 24 -hr 65.85	3.84
AUXBLR	Auxiliary Boiler	690010	4374629	1888	91.4	449.8	18.00	1.52	9.98E-01	2.77E+00	N/A	5.54E-01	1.39E+00	4.99E-02
DIESGEN	3 MW Diesel Generator	690390	4373576	1895	6.09	710.9	22.01	0.69	2.92E+00	1.33E-01	N/A	1.67E-01	2.39E-03	6.67E-01
RAILF	Locomotive Idle - Front	689137	4375594	1875	6.09	700.0	25.30	0.46	7.33E-01	2.47E+00	N/A	1.50E-01	2.84E-02	1.83E-01
RAILB	Locomotive Idle - Back	688987	4373543	1883	6.09	700.0	25.30	0.46	7.33E-01	2.47E+00	N/A	1.50E-01	2.84E-02	1.83E-01
FRPMP	Fire Pump	689284	4374181	1883	3.05	836.5	26.59	0.30	5.69E-01	2.62E-02	N/A	3.28E-02	4.04E-04	1.31E-01
FRPMP2	90 hp Diesel Fire Water Booster Pump	690010	4374597	1889	3.05	308.2	5.27	0.20	9.25E-02	2.23E-03	N/A	7.50E-03	4.62E-05	1.09E-02
DIESGEN500	750 kW Diesel Generator	690006	4374628	1889	6.09	805.4	22.74	0.36	7.29E-01	3.33E-02	N/A	4.17E-02	5.20E-04	1.67E-01
DIESPMP	Emergency Quench Water System Diesel Pump	689284	4374168	1883	3.05	810.9	20.05	0.30	4.93E-01	1.42E-02	N/A	2.84E-02	3.50E-04	7.11E-02
SPKGEN	Propane Spark Ignited Communication Auxiliary Generator	690373	4373576	1895	1.36	901.2	29.71	0.10	4.03E-03	1.09E-02	N/A	7.56E-04	1.89E-03	6.30E-04
MDC-1	Car Dumper Dust Collector	689455	4375621	1880	1.83	Ambient	18.39	2.29	N/A	N/A	N/A	8.64E-01	N/A	N/A
MDC-2	Transfer Tower #1 Dust Collector	689549	4375331	1883	61.00	Ambient	15.75	0.87	N/A	N/A	N/A	1.13E-01	N/A	N/A
MDC-3	Transfer Tower #2 Dust Collector	689759	4375242	1885	61.00	Ambient	15.75	0.87	N/A	N/A	N/A	1.13E-01	N/A	N/A
MDC-4	Crusher Building Dust Collector	690018	4375264	1887	36.58	Ambient	17.24	0.91	N/A	N/A	N/A	1.24E-01	N/A	N/A
MDC-5	Transfer Tower #3 Dust Collector	690020	4374602	1889	61.00	Ambient	15.75	0.87	N/A	N/A	N/A	1.13E-01	N/A	N/A
CDC-1	Coal Storage Dome #1 Dust Collector (live storage)	689443	4375371	1883	1.83	Ambient	18.46	2.21	N/A	N/A	N/A	8.10E-01	N/A	N/A
CDC-2	Coal Storage Dome #2 Dust Collector (live storage)	689666	4375314	1883	1.83	Ambient	18.46	2.21	N/A	N/A	N/A	8.10E-01	N/A	N/A
CDC-3	Coal Reclaim Conveyor and Tunnel #1 Dust Collector	689533	4375340	1883	1.83	Ambient	18.96	0.63	N/A	N/A	N/A	5.94E-02	N/A	N/A
CDC-4	Coal Reclaim Conveyor and Tunnel #2 Dust Collector	689570	4375339	1883	1.83	Ambient	18.96	0.63	N/A	N/A	N/A	5.94E-02	N/A	N/A
CDC-5	Coal Tripper Floor Unit #1 Dust Collector A	690018	4375264	1887	36.58	Ambient	17.24	0.91	N/A	N/A	N/A	1.24E-01	N/A	N/A
CDC-6	Coal Tripper Floor Unit #1 Dust Collector B	690018	4375264	1887	36.58	Ambient	17.24	0.91	N/A	N/A	N/A	1.24E-01	N/A	N/A
CDC-7	Coal Tripper Floor Unit #2 Dust Collector A	690018	4375264	1887	36.58	Ambient	17.24	0.91	N/A	N/A	N/A	1.24E-01	N/A	N/A
CDC-8	Coal Tripper Floor Unit #2 Dust Collector B	690018	4375264	1887	36.58	Ambient	17.24	0.91	N/A	N/A	N/A	1.24E-01	N/A	N/A
LDC-1	Limestone Preparation Building Dust Collector	690108	4374864	1890	24.38	Ambient	16.56	0.38	N/A	N/A	N/A	2.16E-02	N/A	N/A

MODELED POINT SOURCE EMISSIONRATES AND STACK PARAMETERS (CONTINUED)

POINT SOURCES														
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (m)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (meters)	Modeled Emission Rates (g/s)[1]					
									CO	NO_X	Pb	PM_{10}	SO_2	VOC
LDC-2	Limestone Silo A Dust Collector	690108	4374864	1890	24.38	Ambient	17.73	0.16	N/A	N/A	N/A	7.56E-03	N/A	N/A
LDC-3	Limestone Silo B Dust Collector	690108	4374864	1890	24.38	Ambient	17.73	0.16	N/A	N/A	N/A	7.56E-03	N/A	N/A
LDC-4	Limestone Reclaim Tunnel Dust Collector	690108	4374890	1890	1.83	Ambient	21.89	0.38	N/A	N/A	N/A	2.23E-02	N/A	N/A
LDC-5	Limestone Unloading Building dust collector	690143	4375027	1890	1.83	Ambient	19.40	1.52	N/A	N/A	N/A	4.05E-01	N/A	N/A
ACD-1	Fly Ash Silo 1 Dust	690177	4374998	1890	30.48	324.8	14.63	0.19	N/A	N/A	N/A	1.08E-02	N/A	N/A
ACD-2	Fly Ash Silo 2 Dust	690201	4374998	1890	30.48	324.8	14.63	0.19	N/A	N/A	N/A	1.08E-02	N/A	N/A
ACD-3	Bottom Ash Silo 1 Dust Collector	690026	4374693	1890	30.48	324.8	14.63	0.19	N/A	N/A	N/A	1.08E-02	N/A	N/A
ACD-4	Bottom Ash Silo 2 Dust Collector	690118	4374693	1890	30.48	324.8	14.63	0.19	N/A	N/A	N/A	1.08E-02	N/A	N/A
IDC-1	DSI Storage Silo Unit 1 Dust Collector	690023	4374729	1890	22.80	Ambient	15.20	0.15	N/A	N/A	N/A	6.48E-03	N/A	N/A
IDC-2	PAC Storage Silo Unit 1 Dust Collector	690023	4374718	1890	21.30	Ambient	15.20	0.15	N/A	N/A	N/A	6.48E-03	N/A	N/A
IDC-3	DSI Storage Silo Unit 2 Dust Collector	690194	4374729	1890	22.80	Ambient	15.20	0.15	N/A	N/A	N/A	6.48E-03	N/A	N/A
IDC-4	PAC Storage Silo Unit 2 Dust Collector	690194	4374718	1890	21.30	Ambient	15.20	0.15	N/A	N/A	N/A	6.48E-03	N/A	N/A
WDC-1	Soda Ash Storage Silo Dust Collector	689892	4374733	1888	15.20	Ambient	15.20	0.15	N/A	N/A	N/A	6.48E-03	N/A	N/A
WDC-2	Lime Storage Silo Dust Collector	689907	4374733	1888	52.00	Ambient	15.20	0.15	N/A	N/A	N/A	6.48E-03	N/A	N/A
WDC-3	Magnesium Hydroxide (MgOH) Dust Collector	689922	4374733	1888	52.00	Ambient	15.20	0.15	N/A	N/A	N/A	6.48E-03	N/A	N/A
FE-1	Secondary fuel/startup and emergency power - 2,000,000 gallon diesel tank	689995	4375099	1888	9.75	Ambient	0.08	0.16	N/A	N/A	N/A	N/A	N/A	3.33E-03
FE-2	Rail Power Refueling - 1,000,000 gallon diesel tank	689030	4373602	1883	9.75	Ambient	0.08	0.16	N/A	N/A	N/A	N/A	N/A	2.01E-03
FE-3	Burner Supply - 60,000 gallon diesel tank	690192	4374645	1890	18.29	Ambient	0.08	0.16	N/A	N/A	N/A	N/A	N/A	5.01E-04
FE-4	Burner Supply - 60,000 gallon diesel tank	690192	4374618	1890	18.29	Ambient	0.08	0.16	N/A	N/A	N/A	N/A	N/A	5.01E-04
FE-5	Auxiliary Boiler/Emergency Generator - 15,000 gallon diesel tank	689980	4374648	1890	3.66	Ambient	0.08	0.16	N/A	N/A	N/A	N/A	N/A	2.28E-04
FE-6	Main Fire Water Pump - 700 gallon diesel tank	689268	4374182	1883	2.13	Ambient	0.08	0.06	N/A	N/A	N/A	N/A	N/A	1.73E-06
FE-7	Booster Fire Water Pump - 200 gallon diesel tank	689980	4374616	1890	1.83	Ambient	0.08	0.06	N/A	N/A	N/A	N/A	N/A	1.15E-06

MODELED POINT SOURCE EMISSIONRATES AND STACK PARAMETERS (CONTINUED)

POINT SOURCES														
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (m)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (meters)	Modeled Emission Rates (g/s)[1]					
									CO	NO_X	Pb	PM_{10}	SO_2	VOC
FE-8	Emergency Quench Water Pump - 700 gallon diesel tank	689268	4374168	1883	2.13	Ambient	0.08	0.06	N/A	N/A	N/A	N/A	N/A	1.73E-06
FE-9	Switchyard Backup Power Supply - 700 gallon diesel tank	690386	4373625	1895	2.13	Ambient	0.08	0.06	N/A	N/A	N/A	N/A	N/A	1.73E-06
FE-10	Coal Yard Equipment Fueling - 25,000 gallon	689304	4375498	1880	3.35	Ambient	0.08	0.16	N/A	N/A	N/A	N/A	N/A	1.95E-04
FE-11	Ash Haul Truck/Light Vehicle Fueling - 15,000 gallon diesel tank	690202	4375158	1890	3.35	Ambient	0.08	0.16	N/A	N/A	N/A	N/A	N/A	2.75E-05
FE-12	Ash Haul Truck/Light Vehicle Refueling - 15,000 gallon gasoline tank	690212	4375158	1890	3.66	Ambient	0.08	0.13	N/A	N/A	N/A	N/A	N/A	5.27E-02
TC1-1	Tower1Cell01	689742	4374247	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-2	Tower1Cell02	689742	4374259	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-3	Tower1Cell03	689742	4374272	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-4	Tower1Cell04	689742	4374284	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-5	Tower1Cell05	689742	4374296	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-6	Tower1Cell06	689742	4374308	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-7	Tower1Cell07	689742	4374320	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-8	Tower1Cell08	689742	4374332	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-9	Tower1Cell09	689742	4374344	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-10	Tower1Cell10	689742	4374357	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-11	Tower1Cell11	689742	4374369	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-12	Tower1Cell12	689742	4374381	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-13	Tower1Cell13	689742	4374393	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-14	Tower1Cell14	689742	4374405	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-15	Tower1Cell15	689742	4374417	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-16	Tower1Cell16	689742	4374430	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-17	Tower1Cell17	689742	4374442	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-18	Tower1Cell18	689742	4374454	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-19	Tower1Cell19	689742	4374466	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-20	Tower1Cell20	689742	4374478	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-21	Tower1Cell21	689742	4374490	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-22	Tower1Cell22	689742	4374503	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-23	Tower1Cell23	689742	4374515	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC1-24	Tower1Cell24	689742	4374527	1887	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-1	Tower2Cell01	690383	4374244	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-2	Tower2Cell02	690383	4374256	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-3	Tower2Cell03	690383	4374268	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-4	Tower2Cell04	690383	4374280	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-5	Tower2Cell05	690383	4374292	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-6	Tower2Cell06	690383	4374304	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-7	Tower2Cell07	690383	4374317	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-8	Tower2Cell08	690383	4374329	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A

MODELED POINT SOURCE EMISSIONRATES AND STACK PARAMETERS (CONTINUED)

POINT SOURCES														
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (m)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (meters)	Modeled Emission Rates (g/s)[1]					
									CO	NO_X	Pb	PM_{10}	SO_2	VOC
TC2-9	Tower2Cell09	690383	4374341	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-10	Tower2Cell10	690383	4374353	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-11	Tower2Cell11	690383	4374365	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-12	Tower2Cell12	690383	4374377	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-13	Tower2Cell13	690383	4374390	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-14	Tower2Cell14	690383	4374402	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-15	Tower2Cell15	690383	4374414	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-16	Tower2Cell16	690383	4374426	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-17	Tower2Cell17	690383	4374438	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-18	Tower2Cell18	690383	4374450	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-19	Tower2Cell19	690383	4374463	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-20	Tower2Cell20	690383	4374475	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-21	Tower2Cell21	690383	4374487	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-22	Tower2Cell22	690383	4374499	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-23	Tower2Cell23	690383	4374511	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A
TC2-24	Tower2Cell24	690383	4374523	1895	14.33	284.6	7.15	10.00	N/A	N/A	N/A	3.28E-02	N/A	N/A

MODELED VOLUME SOURCE EMISSIONRATES AND RELEASE PARAMETERS

VOLUME SOURCES														
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (m)	Release Height (meters)	Sigma-Y	Sigma-Z	Modeled Emission Rates (g/s)[1]					
								CO	NOX	Pb	PM_{10}	SO2	VOC
CH-1	Coal Unloading Belt Feeder Transfer Point	689463	4375553	1880	9.14	3.5	4.3	N/A	N/A	N/A	0.00E+00	N/A	N/A
CH-2	Coal Stockout Conveyor	689887	4375285	1885	9.14	3.5	4.3	N/A	N/A	N/A	8.85E-03	N/A	N/A
CH-3	Active Coal Pile Wind Erosion and Maintenance	689523	4375168	1883	9.14	26.3	4.3	N/A	N/A	N/A	2.45E-01	N/A	N/A
CH-4	Inactive Portion of Coal Pile Wind Erosion - Phase I	689500	4375058	1883	9.14	100.2	4.3	N/A	N/A	N/A	3.27E-03	N/A	N/A
LH-1	Limestone Unloading Conveyor Transfer Point	690136	4375075	1889	21.34	3.5	9.9	N/A	N/A	N/A	1.54E-02	N/A	N/A
LH-2	Limestone Silo A Loading Conveyor Transfer Point	690108	4374864	1890	21.34	3.5	9.9	N/A	N/A	N/A	4.87E-03	N/A	N/A
LH-3	Limestone Silo B Loading Conveyor Transfer Point	690108	4374864	1890	21.34	3.5	9.9	N/A	N/A	N/A	4.87E-03	N/A	N/A
LH-4	Limestone Pile Wind Erosion and Maintenance	690120	4375135	1889	21.34	12.8	9.9	N/A	N/A	N/A	1.75E-01	N/A	N/A
GH-1	Gypsum Stockout Conveyor	690066	4374942	1890	7.62	3.5	3.5	N/A	N/A	N/A	1.42E-02	N/A	N/A
GH-2	Gypsum Pile Wind Erosion and Maintenance	690044	4374963	1890	7.62	11.6	3.5	N/A	N/A	N/A	2.61E-02	N/A	N/A
LF-1	Landfill Inactive Pile Wind Erosion - area 1	690889	4376051	1890	24.38	325.6	11.3	N/A	N/A	N/A	0.00E+00	N/A	N/A
LF-2	Landfill Inactive Pile Wind Erosion - area 2	689505	4376127	1880	24.38	318.6	11.3	N/A	N/A	N/A	0.00E+00	N/A	N/A
LF-3	Landfill Inactive Pile Wind Erosion - 5 yr cell	689153	4376496	1870	24.38	160.5	11.3	N/A	N/A	N/A	0.00E+00	N/A	N/A
LF-4	Landfill Stockout	689153	4376496	1870	24.38	3.5	11.3	N/A	N/A	N/A	4.34E-04	N/A	N/A
LF-5	Landfill Active Pile Wind Erosion and Maintenance	689153	4376496	1870	24.38	46.5	11.3	N/A	N/A	N/A	3.07E-01	N/A	N/A
Limestone Supply	Total route emissions, see map for routes[2]				see A6-54	see A6-54	see A6-54	N/A	N/A	N/A	2.83E-02	N/A	N/A
Lime Supply	Total route emissions, see map for routes[2]				see A6-54	see A6-54	see A6-54	N/A	N/A	N/A	5.49E-03	N/A	N/A
Sorbent Supply	Total route emissions, see map for routes[2]				see A6-54	see A6-54	see A6-54	N/A	N/A	N/A	1.65E-02	N/A	N/A

MODELED VOLUME SOURCE EMISSIONRATES AND RELEASE PARAMETERS (CONTINUED)

VOLUME SOURCES													
Source Name	Source Description	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Elevation (m)	Release Height (meters)	Sigma-Y	Sigma-Z	Modeled Emission Rates (g/s)[1]					
								CO	NOX	Pb	PM_{10}	SO2	VOC
Soda Ash Supply	Total route emissions, see map for routes[2]				see A6-54	see A6-54	see A6-54	N/A	N/A	N/A	1.69E-02	N/A	N/A
Magnesium Hydroxide Supply	Total route emissions, see map for routes[2]				see A6-54	see A6-54	see A6-54	N/A	N/A	N/A	4.39E-03	N/A	N/A
Scrubber Sludge trucked to Landfill	Total route emissions, see map for routes[2]				see A6-54	see A6-54	see A6-54	N/A	N/A	N/A	8.13E-02	N/A	N/A
Fly Ash trucked to Landfill	Total route emissions, see map for routes[2]				see A6-54	see A6-54	see A6-54	N/A	N/A	N/A	1.60E-01	N/A	N/A
Bottom Ash trucked to Landfill	Total route emissions, see map for routes[2]				see A6-54	see A6-54	see A6-54	N/A	N/A	N/A	4.55E-02	N/A	N/A

NEARBY POINT SOURCE (WHITE PINE ENERGY) EMISSION RATES AND STACK PARAMETERS

Source Name	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (m)	Modeled Emission Rate (g/s)			
							CO	NO_x	PM_{10}	SO_2
S01_S02	691242.7	4399588	182.88	347	19.81	9.57	197.2	92.0	49.95	116.4
S03	691362	4399588	182.88	347	19.81	6.77	98.6	46.0	24.97	58.2
S05	691238.4	4399461	68.58	627.6	18.11	2.21	1.85	0.264	2.31	0.072
S06	690904	4399120	1.52	293.2	0.01	1	NA	NA	0.065	NA
S08	690706.9	4399432	1.52	293.2	21.47	0.3	NA	NA	0.0359	NA
S10	690671	4399359	28.04	293.2	0.01	1	NA	NA	0.1196	NA
S13	690571.8	4399377	1.52	293.2	19.09	0.46	NA	NA	0.0717	NA
S15	690958.6	4399363	42.67	293.2	19.09	0.46	NA	NA	0.0717	NA
S17	691309.6	4399423	86.87	293.2	23.86	0.91	NA	NA	0.3586	NA
S20	691319.4	4399445	1.52	293.2	0.01	1	NA	NA	5.39E-04	NA
S22	691319.3	4399463	1.52	293.2	0.01	1	NA	NA	5.39E-04	NA
S23	691319.3	4399469	1.52	293.2	0.01	1	NA	NA	2.02E-03	NA
S25	692104.1	4401105	1.52	293.2	0.01	1	NA	NA	2.02E-03	NA
S26	691263.6	4399642	22.86	293.2	20.04	0.46	NA	NA	0.1506	NA
S27	691221	4399637	10.67	293.2	19.09	0.46	NA	NA	0.0717	NA
S28	691212.9	4399641	1.52	293.2	0.01	1	NA	NA	2.18E-03	NA
S30	692046.6	4401047	1.52	293.2	0.01	1	NA	NA	2.18E-03	NA
S33	691140	4399425	10.67	293.2	22.55	0.3	NA	NA	0.0753	NA
S35	690926.3	4399465	10.67	293.2	17.06	1.22	NA	NA	0.4558	NA
S37	691136.8	4399449	18.29	293.2	20.04	0.46	NA	NA	0.1506	NA
S44	691238.6	4399439	7.62	699.8	45.72	0.37	0.332	0.1798	0.0293	3.05E-03
S45	691091.6	4399539	10.67	699.8	45.72	0.18	0.3243	0.0167	0.0499	6.20E-04

NEARBY AREA AND VOLUME SOURCE (WHITE PINE ENERGY) EMISSION RATES AND STACK PARAMETERS

Source Name	Source Type	NAD 83 UTM Location (mE)	NAD 83 UTM Location (mN)	Release Height (meters)	areacirc = radius areapoly = number of vertices volume = sigma y	Sigma Zinit	Modeled Emission Rate (g/s)
							PM_{10}
S07	AREACIRC	690671.1	4399436	9.91	26.36	4.61	4.28E-05
S11	AREACIRC	690718.2	4399359	14.02	37.18	6.52	4.30E-05
S12	AREACIRC	690623.8	4399359	14.02	37.18	6.52	4.30E-05
S18	AREAPOLY	690807.2	4399300	9.14	4	4.25	7.29E-07
S32 S38	AREAPOLY	690050.9	4401032	0	4	0	8.76E-08
S39.1 – S39.56[a]	VOLUME	691421.2	4398741	3.05	17.01	1.42	2.84E-04

NEARBY SOURCE EMISSION RATES AND STACK PARAMETERS

Facility Name	Source ID	Pollutant	Emission Rate (g/s)	UTM Location (mE)	UTM Location (mN)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (meters)
H E Hunewill Construction Co., Inc.	0171am	PM_{10}	10.67	740760	4321140	10.00	295.37	0.00001	1.01
	0171am	SO_2	4.02	740760	4321140	10.00	295.37	0.00001	1.01
	0171048a	PM_{10}	0.37	740760	4321140	12.65	422.04	5.346	1.01
	0171048a	SO_2	2.12	740760	4321140	12.65	422.04	5.346	1.01
	0171048b	PM_{10}	0.37	740760	4321140	12.65	422.04	5.346	1.01
	0171048b	SO_2	2.12	740760	4321140	12.65	422.04	5.346	1.01
	171049	PM_{10}	2.14	740760	4321140	12.65	422.04	32.667	1.01
	171049	SO_2	2.65	740760	4321140	12.65	422.04	32.667	1.01
Robinson Nevada Mining Company	0373am	PM_{10}	12.12	671580	4347540	10.00	295.37	0.00001	1.01
	0373am	SO_2	0.51	671580	4347540	10.00	295.37	0.00001	1.01
	0373am	NO_x	0.736	671580	4347540	10.00	295.37	0.00001	1.01
	373008	PM_{10}	0.02	671580	4347540	9.14	295.37	0.00001	0.67
	373002	PM_{10}	0.33	671580	4347540	8.99	292.98	10.109	0.91
	373005	PM_{10}	0.33	671580	4347540	10.00	296.09	10.110	0.91
	373006	PM_{10}	0.07	671580	4347540	15.00	292.98	9.676	0.43
	373009	PM_{10}	0.10	671580	4347540	6.00	324.98	4.450	0.76
	373010	PM_{10}	0.13	671580	4347540	6.00	324.98	5.795	0.76
	373011	PM_{10}	0.003	671580	4347540	6.00	354.98	9.675	0.70
	373017	PM_{10}	0.05	671580	4347540	2.99	874.82	14.513	0.58
	373017	SO_2	0.18	671580	4347540	2.99	874.82	14.513	0.58
	373017	NO_x	0.078	671580	4347540	2.99	874.82	14.513	0.58
Newmont Gold Company	0405am	PM_{10}	1.00	583930	4495990	10.00	295.37	0.00001	1.01
J & M Trucking, Inc.	543001	PM_{10}	0.04	684020	4346150	10.00	342.76	2.052	1.52
	0543am	PM_{10}	0.07	684020	4346150	10.00	295.37	0.00001	1.01

NEARBY SOURCE EMISSION RATES AND STACK PARAMETERS (CONTINUED)

Facility Name	Source ID	Pollutant	Emission Rate (g/s)	UTM Location (mE)	UTM Location (mN)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (meters)
Homestake Mining Company	713019	PM_{10}	0.002	589940	4376280	21.42	333.15	10.097	0.10
Reck Brothers	0835am	PM_{10}	0.45	689110	4348990	10.00	295.37	0.00001	1.01
	0835am	PM_{10}	0.12	689110	4348990	10.00	295.37	0.00001	1.01
	0835am	NO_x	0.296	689110	4348990	10.00	295.37	0.00001	1.01
Nevada Slag, Inc.	1065am	PM_{10}	0.87	691300	4364600	10.00	295.37	0.00001	1.01
	1065am	PM_{10}	0.93	691300	4364600	10.00	295.37	0.00001	1.01
	1065am	NO_x	0.308	691300	4364600	10.00	295.37	0.00001	1.01
Reed Distributing, Inc.	1124001	PM_{10}	0.0003	682780	4348580	6.10	505.37	0.809	0.61
	1124001	PM_{10}	0.0003	682780	4348580	6.10	505.37	0.809	0.61
J & M Trucking, Inc.	1177am	PM_{10}	0.07	589410	4373560	10.00	295.37	0.00001	1.01
Bald Mountain Mine Properties	1336am	PM_{10}	0.03	630900	4420250	10.00	295.37	0.00001	1.01
Bald Mountain Mine Properties	1362001a	PM_{10}	0.03	617000	4423100	10.67	322.04	0.356	0.30
	1362001b	PM_{10}	0.002	617000	4423100	10.67	588.71	2.329	0.30
	1362001b	PM_{10}	0.002	617000	4423100	10.67	588.71	2.329	0.30
	1362002	PM_{10}	0.0001	617000	4423100	10.67	588.71	2.329	0.30
	1362002	PM_{10}	0.0001	617000	4423100	10.67	588.71	2.329	0.30
	1362003a	PM_{10}	0.01	617000	4423100	10.67	310.93	4.858	0.91
	1362003b	PM_{10}	0.0001	617000	4423100	10.67	310.93	4.858	0.91
	1362003b	PM_{10}	0.000	617000	4423100	10.67	310.93	4.858	0.91
	1362001	NO_x	0.056	617000	4423100	10.67	747.04	10.083	0.13
	1362002	NO_x	0.001	617000	4423100	10.67	588.71	2.329	0.30
	1362003	NO_x	0.016	617000	4423100	10.67	310.93	4.858	0.91
Cooper & Sons, Inc.	1377am	PM_{10}	0.74	688350	4356200	10.00	295.37	0.00001	1.01
	1377am	PM_{10}	0.62	688350	4356200	10.00	295.37	0.00001	1.01
	1377am	NO_x	0.406	688350	4356200	10.00	295.37	0.00001	1.01
Country Construction	1417001	PM_{10}	0.42	685820	4353520	10.00	295.37	0.00001	1.01
White Pine County School District	1466001	PM_{10}	0.26	684170	4346840	12.19	449.82	0.00003	0.46

NEARBY SOURCE EMISSION RATES AND STACK PARAMETERS (CONTINUED)

Facility Name	Source ID	Pollutant	Emission Rate (g/s)	UTM Location (mE)	UTM Location (mN)	Stack Height (meters)	Stack Temperature (K)	Exit Velocity (m/s)	Stack Diameter (meters)
	1466001	SO_2	0.01	684170	4346840	12.19	449.82	0.00003	0.46
	1466001	NO_x	0.041	684170	4346840	12.19	449.82	0.00003	0.46
Chevron Environmental Management Company	1594001	NO_x	0.053	683560	4347130	10.00	295.37	0.00001	1.01
U.S. Army - Dugway Proving Ground - Utah	10706	SO_2	0.66	820553	4448686	10.00	422.00	9.14	0.30

Attachment 3B

Modeling Inventory Developed for Class I SO2 PSD Increment Analysis

(Used for Class I SO2 Increment Analysis)

White Pine Energy Station
Modeling Source Inventory - Cumulative Sources of SO_2

State	County	Company Name	Facility Name	Emission Point Description	UTM Zone 11 East (m)	UTM Zone 11 North (m)	Emission Rate (lb/hr)
NV	Elko	QUEENSTAKE RESOURCES USA, INC.	CLASS 1A -SSX PROJECT / INDEPENDENCE	SYSTEM 27 - HEAT CIRCUIT	591,760	4,584,600	0.032
NV	Elko	QUEENSTAKE RESOURCES USA, INC.	CLASS 1A -SSX PROJECT / INDEPENDENCE	SYSTEM 40 - WEST ROASTER PROCESS	591,760	4,584,600	2.91
NV	Elko	QUEENSTAKE RESOURCES USA, INC.	CLASS 1A -SSX PROJECT / INDEPENDENCE	SYSTEM 42 - EAST ROASTER PROCESS	591,760	4,584,600	2.91
NV	Elko	QUEENSTAKE RESOURCES USA, INC.	CLASS 1A -SSX PROJECT / INDEPENDENCE	SYSTEM 35 - DRY MILL CIRCUIT - ORE DRYING PROCESS	591,760	4,584,600	14.5
NV	Elko	HECLA VENTURES CORPORATION	CLASS 1 -HOLLISTER BLOCK DEVELOPMENT PROJECT	BACK-UP POWER GENERATION	536,800	4,550,500	1.52
NV	Elko	HECLA VENTURES CORPORATION	CLASS 1 -HOLLISTER BLOCK DEVELOPMENT PROJECT	POWER GENERATION	536,800	4,550,500	6.08
NV	Elko	CITY OF ELKO	CLASS 1 -ELKO SANITARY LANDFILL	SYSTEM 2 - GRINDING OPERATION - TREE & WOOD WASTES	607,600	4,521,200	0.45
NV	Elko	CITY OF ELKO	CLASS 1 -ELKO SANITARY LANDFILL	SYSTEM 2 ALT. OP. SCENARIO - GRINDING OPS. - ASPHALT MAT.	607,600	4,521,200	0.45
NV	Elko	GRAYMONT WESTERN US, INC	CLASS 1 - PILOT PEAK TITLE V	SYSTEM 12 - KILN 1 CIRCUIT (D-85)	734,420	4,522,850	14.0
NV	Elko	GRAYMONT WESTERN US, INC	CLASS 1 - PILOT PEAK TITLE V	SYSTEM 16 - KILN 2 CIRCUIT (D-285)	734,420	4,522,850	21.0
NV	Elko	GRAYMONT WESTERN US, INC	CLASS 1 - PILOT PEAK TITLE V	SYSTEM 21 - KILN 3 CIRCUIT (D-385)	734,420	4,522,850	33.6
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 84 - OXYGEN PLANT REGENERATIVE HEATER	568,120	4,512,620	0.005
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 60 - LIQUID SULFUR/ACID TANK HEATERS	568,120	4,512,620	0.04
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 68 - CARBON STRIPPING BOILER #3	568,120	4,512,620	0.05
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 69 - CARBON STRIPPING BOILER #4	568,120	4,512,620	0.05
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 70 - CARBON STRIPPING BOILER #5	568,120	4,512,620	0.05
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 71 - CARBON STRIPPING BOILER #6	568,120	4,512,620	0.05
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 74 - PROPANE VAPORIZER	568,120	4,512,620	0.07
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 75 - PROPANE VAPORIZER	568,120	4,512,620	0.07
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 76 - PROPANE VAPORIZER	568,120	4,512,620	0.07

White Pine Energy Station
Modeling Source Inventory - Cumulative Sources of SO_2

State	County	Company Name	Facility Name	Emission Point Description	UTM Zone 11 East (m)	UTM Zone 11 North (m)	Emission Rate (lb/hr)
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 58 - CFB NORTH ROASTER OXYGEN PREHEATER	568,120	4,512,620	0.07
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 59 - CFB SOUTH ROASTER OXYGEN PREHEATER	568,120	4,512,620	0.07
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 67 - CARBON STRIPPING BOILER #2	568,120	4,512,620	0.07
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 66 - CARBON STRIPPING BOILER #1	568,120	4,512,620	0.09
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 45 - ACID PLANT STARTUP HEATER	568,120	4,512,620	0.16
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 72 - CARBON REGENERATION KILN #1	568,120	4,512,620	0.17
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 73 - CARBON REGENERATION KILN #2	568,120	4,512,620	0.17
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 43 - NORTH CFB PREHEATER & SOUTH CFB PREHEATER	568,120	4,512,620	12.9
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 42 - MILL 6 STATIC SEPARATOR	568,120	4,512,620	27.4
NV	Eureka	NEWMONT MINING CORPORATION	CLASS 1B -GOLD QUARRY	SYSTEM 44 - N. CFB ROASTER, S. CFB ROASTER & RTO	568,120	4,512,620	39.5
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	ANCILLARY EQUIPMENT- PROPANE VAPORIZERS	554,700	4,536,310	0.004
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	PROPANE VAPORIZERS #1-#3	554,700	4,536,310	0.004
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	AUTOCLAVE CIRCUIT BOILER #1 (S2.021)	554,700	4,536,310	0.01
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	OXYGEN PLANT LIQUID OXYGEN VAPORIZER	554,700	4,536,310	0.02
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	AUTOCLAVE CIRCUIT BOILER #2&3 (S2.022 - 2.023)	554,700	4,536,310	0.03
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	RODEO MINE AIR HEATERS	554,700	4,536,310	0.05
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	AUTOCLAVE CIRCUIT BOILER #4 (S2.024)	554,700	4,536,310	0.05
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	MEIKLE MINE- MEIKLE AIR HEATERS	554,700	4,536,310	0.05
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	AUTOCLAVES #1 -#6	554,700	4,536,310	0.29
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	CARBON REACTIVATION KILN 2	554,700	4,536,310	0.30
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	AUTOCLAVES #1 -#6	554,700	4,536,310	0.45
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	AUTOCLAVES #1 -#6	554,700	4,536,310	0.90
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	AUTOCLAVES #1 -#6	554,700	4,536,310	0.90
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	MILL #1 DRY GRINDING PROCESS	554,700	4,536,310	4.28

White Pine Energy Station
Modeling Source Inventory - Cumulative Sources of SO_2

State	County	Company Name	Facility Name	Emission Point Description	UTM Zone 11 East (m)	UTM Zone 11 North (m)	Emission Rate (lb/hr)
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	MILL #2 DRY GRINDING PROCESS	554,700	4,536,310	4.28
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	SHOTCRETE PLANT W/AGG DRYER	554,700	4,536,310	10.6
NV	Eureka	BARRICK GOLDSTRIKE MINES, INC	CLASS 1B - GOLDSTRIKE MINE	S2.209 ORE ROASTING PROCESS	554,700	4,536,310	44.9
NV	Eureka	AIR LIQUIDE LARGE INDUSTRIES U.S. L.P.	CLASS 1A -BARRICK GOLDSTRIKE OXYGEN PLANT	COMBINED REACTIVATION GAS HEATER & GAS VAPORIZER	554,600	4,536,000	0.01
NV	Eureka	AIR LIQUIDE LARGE INDUSTRIES U.S. L.P.	CLASS 1A -BARRICK GOLDSTRIKE OXYGEN PLANT	COMBINED REACTIVATION GAS HEATER & GAS VAPORIZER	554,600	4,536,000	0.02
NV	Eureka	NEWMONT NEVADA ENERGY INVESTMENT, LLC	CLASS 1 PSD OPTC -BOULDER VALLEY POWER PROJ.	DIESEL FIREWATER PUMP	539,690	4,510,070	0.07
NV	Eureka	NEWMONT NEVADA ENERGY INVESTMENT, LLC	CLASS 1 PSD OPTC -BOULDER VALLEY POWER PROJ.	BACK-UP COMBUSTION TURBINES, #2 FUEL OIL FIRED	539,690	4,510,070	19.1
NV	Eureka	NEWMONT NEVADA ENERGY INVESTMENT, LLC	CLASS 1 PSD OPTC -BOULDER VALLEY POWER PROJ.	BACK-UP COMBUSTION TURBINES, #2 FUEL OIL FIRED	539,690	4,510,070	19.1
NV	Eureka	NEWMONT NEVADA ENERGY INVESTMENT, LLC	CLASS 1 PSD OPTC -BOULDER VALLEY POWER PROJ.	BACK-UP COMBUSTION TURBINES, #2 FUEL OIL FIRED	539,690	4,510,070	19.1
NV	Eureka	NEWMONT NEVADA ENERGY INVESTMENT, LLC	CLASS 1 PSD OPTC -BOULDER VALLEY POWER PROJ.	BACK-UP COMBUSTION TURBINES, #2 FUEL OIL FIRED	539,690	4,510,070	19.1
NV	Eureka	NEWMONT NEVADA ENERGY INVESTMENT, LLC	CLASS 1 PSD OPTC -BOULDER VALLEY POWER PROJ.	SUB-CRITICAL STEAM BOILER	539,690	4,510,070	193
NV	Humboldt	NEWMONT MINING CORPORATION	CLASS 1B -TWIN CREEKS MINE	SYSTEM 12 - PINON MILL CARBON REGENERATION KILN	485,840	4,567,620	0.004
NV	Humboldt	NEWMONT MINING CORPORATION	CLASS 1B -TWIN CREEKS MINE	SYSTEM 9 - JUNIPER MILL PACKAGE BOILERS - FIRETUBE	485,840	4,567,620	0.005
NV	Humboldt	NEWMONT MINING CORPORATION	CLASS 1B -TWIN CREEKS MINE	SYSTEM 4 - JUNIPER MILL CARBIN KILNS	485,840	4,567,620	0.006
NV	Humboldt	NEWMONT MINING CORPORATION	CLASS 1B -TWIN CREEKS MINE	SYSTEM 20 - OXYGEN PLANT VAPORIZER	485,840	4,567,620	0.01
NV	Humboldt	NEWMONT MINING CORPORATION	CLASS 1B -TWIN CREEKS MINE	SYSTEM 21 - OXYGEN PLANT VAPORIZER	485,840	4,567,620	0.01
NV	Humboldt	NEWMONT MINING CORPORATION	CLASS 1B -TWIN CREEKS MINE	SYSTEM 15 - SAGE MILL STEAM GENERATORS	485,840	4,567,620	0.10
NV	Humboldt	NEWMONT MINING CORPORATION	CLASS 1B -TWIN CREEKS MINE	SYSTEM 14 - SAGE MILL AUTOCLAVES: PRIM. & ALT. OP. SCENARIO	485,840	4,567,620	33.3
NV	Clark	NEVADA POWER COMPANY	PSD - REID-GARDNER GENERATING STATION	SYSTEMS 03A & 03B: STEAM BOILER #3 (B-03)	711,620	4,059,440	680
NV	Clark	NEVADA POWER COMPANY	PSD - REID-GARDNER GENERATING STATION	SYSTEMS 04A & 04B: STEAM BOILER #4 (B-04)	711,620	4,059,440	857

White Pine Energy Station
Modeling Source Inventory - Cumulative Sources of SO_2

State	County	Company Name	Facility Name	Emission Point Description	UTM Zone 11 East (m)	UTM Zone 11 North (m)	Emission Rate (lb/hr)
NV	Clark	Chemical Lime - Apex	Chemical Lime - Apex	Portable Screening Plant Generator	687,325	4,025,734	0.04
NV	Clark	Lasco Bathware	Lasco Bathware	Air Heater - Line 1	712,587	4,062,663	0.01
NV	Clark	Lasco Bathware	Lasco Bathware	Air Heater - Line 1	712,588	4,062,625	0.01
NV	Clark	Lasco Bathware	Lasco Bathware	Air Heater - Line 2	712,634	4,062,663	0.01
NV	Clark	Lasco Bathware	Lasco Bathware	Air Heater - Line 2	712,634	4,062,625	0.01
NV	Clark	Lasco Bathware	Lasco Bathware	Airex RTO	712,581	4,062,663	0.01
NV	Clark	Simplot Silica Products	Simplot Silica Products	Coal fired sand dryer	730,457	4,044,128	7.34
NV	Clark	Simplot Silica Products	Simplot Silica Products	Pit Area	726,784	4,039,557	10.8
NV	Clark	Simplot Silica Products	Simplot Silica Products	Dry Area	730,300	4,044,007	0.96
NV	Clark	Simplot Silica Products	Simplot Silica Products	Portable Dryer	730,484	4,044,118	0.06
NV	Clark	Royal Cement Company	Royal Cement Company	Rotary Kiln	723,301	4,058,917	16.6
NV	Clark	NPC Harry Allen Station	NPC Harry Allen Station	GE Turbine	688,237	4,033,301	45.3
NV	Clark	NPC Harry Allen Station	NPC Harry Allen Station	Cummins Generator	688,184	4,033,358	0.27
NV	Clark	NPC Harry Allen Station	NPC Harry Allen Station	Turbine/HRSG	688,169	4,033,533	1.00
NV	Clark	NPC Harry Allen Station	NPC Harry Allen Station	Turbine/HRSG	688,129	4,033,588	1.00
NV	Clark	NPC Harry Allen Station	NPC Harry Allen Station	Katolight Generator	688,199	4,033,479	0.80
NV	Clark	NPC Harry Allen Station	NPC Harry Allen Station	Caterpillar Generator	688,268	4,033,393	1.60
NV	Clark	NPC Harry Allen Station	NPC Harry Allen Station	GE PG 7 EA Turbine	688,202	4,033,324	0.64
NV	Clark	NPC Harry Allen Station	NPC Harry Allen Station	Clarke Fire Pump	688,150	4,033,424	0.31
NV	Clark	Mirant LLC	Mirant LLC	CTGHRSG1	682,932	4,031,880	1.00
NV	Clark	Mirant LLC	Mirant LLC	CTGHRSG2	682,925	4,031,844	1.00
NV	Clark	Mirant LLC	Mirant LLC	Gasheater - part	682,776	4,031,688	0.005
NV	Clark	Mirant LLC	Mirant LLC	Gasheater - part	682,776	4,031,686	0.005
NV	Clark	Mirant LLC	Mirant LLC	Generator	683,032	4,031,790	2.40
NV	Clark	Mirant LLC	Mirant LLC	Fire Pump	682,863	4,031,820	0.60
NV	Clark	NPC SilverHawk Power Plant	NPC SilverHawk Power Plant	Westinghouse turbine/HRSG	682,958	4,031,122	1.50
NV	Clark	NPC SilverHawk Power Plant	NPC SilverHawk Power Plant	Westinghouse turbine/HRSG	682,997	4,031,147	1.50
NV	Clark	NPC SilverHawk Power Plant	NPC SilverHawk Power Plant	Fire Pump	683,050	4,031,234	0.50
NV	Clark	NPC SilverHawk Power Plant	NPC SilverHawk Power Plant	Generator	682,948	4,031,274	0.01
NV	Clark	Ashgrove Cement (ATC appln)	Ashgrove Cement (ATC appln)	Kiln	699,293	4,044,523	84.0
ID	MINIDOKA	TASCO, Paul	TASCO, Paul	TASCO, Paul	765,970	4,722,588	72.8
ID	MINIDOKA	TASCO, Paul	TASCO, Paul	TASCO, Paul	765,970	4,722,588	0.02
ID	MINIDOKA	TASCO, Paul	TASCO, Paul	TASCO, Paul	765,960	4,722,588	58.6
ID	MINIDOKA	TASCO, Paul	TASCO, Paul	TASCO, Paul	765,888	4,722,771	16.5
ID	MINIDOKA	TASCO, Paul	TASCO, Paul	TASCO, Paul	765,898	4,722,771	20.1
ID	MINIDOKA	TASCO, Paul	TASCO, Paul	TASCO, Paul	765,961	4,722,702	0.78
ID	MINIDOKA	TASCO, Paul	TASCO, Paul	TASCO, Paul	765,955	4,722,711	0.02

White Pine Energy Station
Modeling Source Inventory - Cumulative Sources of SO_2

State	County	Company Name	Facility Name	Emission Point Description	UTM Zone 11 East (m)	UTM Zone 11 North (m)	Emission Rate (lb/hr)
ID	MINIDOKA	TASCO, Paul	TASCO, Paul	TASCO, Paul	765,972	4,722,614	4.37
ID	TWIN FALLS	TASCO, Twin Falls	TASCO, Twin Falls	TASCO, Twin Falls	711,018	4,711,770	186
ID	TWIN FALLS	TASCO, Twin Falls	TASCO, Twin Falls	TASCO, Twin Falls	711,070	4,711,655	225
ID	TWIN FALLS	TASCO, Twin Falls	TASCO, Twin Falls	TASCO, Twin Falls	710,912	4,711,910	13.3
ID	TWIN FALLS	TASCO, Twin Falls	TASCO, Twin Falls	TASCO, Twin Falls	710,972	4,711,898	0.95
ID	TWIN FALLS	TASCO, Twin Falls	TASCO, Twin Falls	TASCO, Twin Falls	710,972	4,711,898	0.48
ID	TWIN FALLS	TASCO, Twin Falls	TASCO, Twin Falls	TASCO, Twin Falls	710,964	4,711,912	1.25
UT	Sevier	Nevco Power Pant	Nevco Power Pant	270 MW Coal-Fired Boiler	935,678	4,311,470	125
UT	Millard	Intermountain Power Plant	Intermountain Power Plant	Unit 1	880,096	4,382,612	455
UT	Millard	Intermountain Power Plant	Intermountain Power Plant	Unit 2	880,096	4,382,612	424
UT	Millard	Intermountain Power Plant	Intermountain Power Plant	Unit 3	879,936	4,382,602	905
UT	Millard	Graymont Western Lime	Graymont Western Lime	Kiln 1	862,670	4,318,192	109
UT	Millard	Graymont Western Lime	Graymont Western Lime	Kiln 2	862,649	4,318,184	25.9
UT	Millard	Graymont Western Lime	Graymont Western Lime	Kiln 3	862,627	4,318,132	29.4
UT	Millard	Graymont Western Lime	Graymont Western Lime	Kiln 4	862,665	4,318,001	38.4
UT	Iron	Genpak Corporation	Polystyrene Foam Production Facility	Natural Gas Heater / Thermal Oxidizer	843,891	4,177,663	0.003
UT	Washington	Kern River Gas Transmission Company	Veyo Compressor Station	SoLoNOx Turbine	793,729	4,138,458	0.22
UT	Washington	Kern River Gas Transmission Company	Veyo Compressor Station	SoLoNOx Turbine	793,729	4,138,458	0.72
UT	Washington	Kern River Gas Transmission Company	Veyo Compressor Station	SoLoNOx Turbine	793,729	4,138,458	0.36
UT	Washington	Kern River Gas Transmission Company	Veyo Compressor Station	Backup Generator	793,729	4,138,458	0.004
UT	Washington	Kern River Gas Transmission Company	Veyo Compressor Station	Boiler	793,729	4,138,458	0.002
UT	Washington	St. George City Power	Red Rock Power Generation Station	Diesel Engine Generator	804,994	4,111,226	0.21
UT	Washington	St. George City Power	Red Rock Power Generation Station	Dual Fuel Engine	804,994	4,111,226	0.14

White Pine Energy Station
Modeling Source Inventory - Cumulative Sources of SO_2

State	County	Company Name	Facility Name	Emission Point Description	UTM Zone 11 East (m)	UTM Zone 11 North (m)	Emission Rate (lb/hr)
UT	Washington	Southern Utah Asphalt	Asphalt Plant in Ft. Pierce Industrial park	Asphalt Plant in Ft. Pierce Industrial park	801,321	4,106,683	0.74
UT	Washington	Progressive Contracting Incorporated	Aggregate Mining	Aggregate Mining	802,645	4,106,366	2.71
UT	Washington	Western Rock Products Corporation	Sorenson Pit	Sorenson Pit	803,107	4,113,312	1.14
UT	Washington	Washington Cty Solid Waste Spcl Svc Dist	Washington County Sanitary Landfill	Washington County Sanitary Landfill	804,105	4,139,027	4.99
UT	Washington	Intermountain Health Care	Dixie Regional Hospital (New)	Dixie Regional Hospital (New)	806,087	4,111,239	6.07
UT	Washington	Sunroc Corporation	Concrete Block Facility	Concrete Block Facility	806,515	4,105,408	0.60
UT	Washington	Sunroc Corporation	Ft. Pearce Concrete Batch & Aggregate Plants	Ft. Pearce Concrete Batch & Aggregate Plants	807,286	4,104,935	2.94
UT	Washington	Western Rock Products Corporation	Fort Pierce Pit	Fort Pierce Pit	808,156	4,104,810	6.85
UT	Washington	Quality Excavation Inc.	Aggregate Plant - Fort Pierce Industrial Park	Aggregate Plant - Fort Pierce Industrial Park	808,823	4,106,957	2.75
UT	Washington	Gilbert Development Corporatior	Aggregate Crushing - SR 9 Pit	Aggregate Crushing - SR 9 Pit	816,958	4,119,403	2.08
UT	Washington	Interstate Rock Products	Hurricane Pit	Hurricane Pit	822,923	4,120,121	0.75
UT	Iron	Western Rock Products Corporation	Cedar City Yard & Ready Mix Plant	Cedar City Yard & Ready Mix Plant	845,457	4,180,613	7.50
UT	Iron	Mel Clark Construction	Cedar City Aggregate Processing Plant	Cedar City Aggregate Processing Plant	845,674	4,180,205	0.09
UT	Iron	Ashdown Brothers Construction	Asphalt Plant/Crusher/Concrete Plant	Asphalt Plant/Crusher/ Concrete Plant	845,957	4,179,852	8.03
UT	Iron	Southern Utah University	Cedar City Campus	Cedar City Campus	846,597	4,176,967	17.0
UT	Iron	Sunroc Corporation	Cedar City Concrete Batching Plant	Cedar City Concrete Batching Plant	847,417	4,179,615	2.01
UT	Iron	Mel Clark Construction	Clark Pit: Aggregate Processing Facility	Clark Pit: Aggregate Processing Facility	848,059	4,194,603	0.09
UT	Washington	Twin City Power	Hildale City Cogeneration Facility	Hildale City Cogeneration Facility	855,757	4,102,512	1.67

White Pine Energy Station
Modeling Source Inventory - Cumulative Sources of SO_2

Per the cumulative SO2 PSD increment modeling protocol agreed upon by WPEA and the National Park Service, the modeling source inventory includes SO2 emissions from all increment-consuming PSD major sources inside the Calpuff modeling domain and all increment-consuming PSD minor sources within 50 km of a Class I receptor. Note that only potentially increment-consuming emissions are included in the modeling inventory. Increment expansion was not included, although increment expansion may have actually occurred due to emissions reductions at some sources in the analysis.

The Calpuff modeling domain includes areas in Nevada, Oregon, Idaho, Utah, and Arizona. Specific details of the modeling source inventory for each state are provided below:

State-Specific Modeling Inventory Details

Jurisdiction	Agency Contact Supplying Inventory Data	Notes
Nevada	Greg Remer, NDEP (phone: 775-687-9359)	Emission rates from the NDEP database are on a potential to emit basis. Since the NDEP database does not flag PSD major sources, al Class 1 facilities (i.e., >100 tpy potential emissions for any criteria pollutant) located within the Calpuff domain were conservatively assumed to be PSD major and were included in the modeling inventory. No Class 2 facilities (i.e., <100 tpy potential for all criteria pollutants) were located within 50 km of a Class I receptor. Since the Reid Gardner Units #1 and #2 were operating prior to the January 6, 1975, baseline date (per email from Greg Remer, NDEP, to David Wilson, LS Power, 09/14/2006) emissions from these units are part of the PSD increment baseline. Therefore, Reid-Gardner Units #1 and #2 are not included in the modeling inventory. Since Reid-Gardner installed SO2 scrubbers after the baseline date, increment expansion by these units could have been documented and modeled.
Nevada (Clark County)	Vasant Rajagopalan, Clark County Department of Air Quality Management (phone: 702-455-5942)	Emission rates for Clark County are on a potential to emit basis. The modeling inventory includes all Clark County PSD major sources within the Calpuff modeling domain. Since Clark County is not within 50 km of a Class I receptor, no Clark County minor sources are included in in the modeling inventory.
Oregon	Mark Bailey, Oregon DEQ (phone: 541-388-6146, ext. 322)	No PSD major sources exist within the Calpuff modeling domain (per email from Mark Bailey, Oregon DEQ, to David Wilson, LS Power, 09/08/2006). Since the Oregon area of the Calpuff modeling domain is not within 50 km of a Class I receptor, no Oregon mino sources are included in the modeling inventory.
Idaho	Gary Reinbold, Idaho DEQ (phone: 208-373-0253)	Emission rates from the Idaho DEQ are actuals. The modeling inventory includes all Idaho PSD major sources within the Calpuff modeling domain. No Idaho PSD minor sources are located within 50 km of a Class I receptor (per email from Gary Reinbold, Idaho DEQ, to David Wilson, LS Power, 09/14/2006).
Utah	Tom Orth, Utah DEQ (phone: 801-536-4005)	Emissions from the Utah DEQ are actuals. The modeling inventory includes all Utah PSD major sources within the Calpuff modeling domain. Potential emissions are modeled for new proposed power plants that have not established actual emissions levels. Several PSD minor sources in Iron and Washington counties are included in the modeling inventory since they are located within 50 km of Class I receptors at Zion.
Arizona	Latha Toopal, ADEQ (phone: 602-771-2273)	The Calpuff modeling domain includes portions of Mohave and Coconino Counties; however, based on source locations provided by ADEQ, there are no PSD major or minor sources located within the modeling domain. Thus, no Arizona sources are included in the modeling inventory.

Attachment 4

Analysis of Sulfur and Nitrogen Deposition

Attachment 4A

Deposition Analysis for Jarbidge Wilderness Area

Sulfur and Nitrogen Deposition

Cumulative Deposition Assessment - Jarbidge Wilderness Area

The total deposition increases due to the WPES, the EEC, Toquop, Newmont, IPP3, and Nevco-Sevier, are evaluated in conjunction with EPA's Clean Air Status and Trends (CASTNET) monitored deposition values to demonstrate that aquatic ecosystems in the area would be safe from acidification effects after construction of the proposed action and the reasonably expected future actions. Predicted total deposition increases are presented below, along with actual monitored values applicable to Jarbidge from the CASTNET monitoring network.

Table 1. Sulfur Deposition at Jarbidge

Total S Deposition Increase (kg/ha/yr) (1)	CASTNET Monitored Existing S Deposition (kg/ha/yr) (2)	Total Predicted S Deposition (kg/ha/yr)
0.03	0.91	0.94

Notes:

(1) Total predicted sulfur deposition due to the WPES, EEC, Toquop, Newmont, IPP3, and Nevco-Sevier calculated in Attachment 1.

(2) Per USDA Forest Service, Saval Ranch CASTNET deposition data is representative of Jarbidge. For the Saval Ranch site, wet and dry deposition values are available for the date range 1990 through 1993. The worst-case deposition occurred in 1993 and is represented in the table. Site-specific deposition charts are included at the end of this analysis.

Table 2. Nitrogen Deposition at Jarbidge

Total N Deposition Increase (kg/ha/yr) (1)	CASTNET Monitored Existing N Deposition (kg/ha/yr) (2)	Total Predicted N Deposition (kg/ha/yr)
0.008	2.0	2.01

Notes:

(1) Total predicted nitrogen deposition due to the WPES, EEC, Toquop, Newmont, IPP3, and Nevco-Sevier calculated in Attachment 1.

(2) Per USDA Forest Service, Saval Ranch CASTNET deposition data is representative of Jarbidge. For the Saval Ranch site, wet and dry deposition values are available for the date range 1990 through 1993. The worst-case deposition occurred in 1993 and is represented in the table. Site-specific deposition charts are included at the end of this analysis.

The USDA Forest Service research paper *Estimating Lake Susceptibility to Acidification Due to Acid Deposition* (the Paper) provides a procedure for predicting acid deposition effects on aquatic ecosystems. Figure 3 of the paper represents "safe lines" on a plot of deposition vs. base cation concentration. Lakes that fall on the right side of the "safe lines" are not expected to be adversely affected by the corresponding deposition levels. The Figure 3 "lookup" values corresponding to Jarbidge are discussed below.

Sulfur and Nitrogen Deposition

Cumulative Deposition Assessment - Jarbidge Wilderness Area

In high elevation Western lakes, both sulfur and nitrogen deposition can contribute to aquatic acidity. For such lakes, the Paper indicates that the total deposition used as a "lookup" value in Figure 3 should include all sulfur deposition, plus 25% of the nitrogen deposition to account for the acidification potential of inorganic nitrogen.

Emerald Lake is a high-elevation lake identified at Jarbidge with a population of brook trout documented by the Nevada Division of Wildlife (NDOW). The alkalinity of Emerald Lake is reported by NDOW as 342 μeq/L. Alkalinity serves as a worst-case indicator for acid neutralization capacity (ANC). Assuming a worst-case 1:1 relationship between ANC and base cation concentration (per Figure 1 of the paper), the worst-case base cation concentration would be 342 μeq/L. The "lookup" values for Figure 3 of the Paper are provided in Table 3 below.

Table 3. Lookup Values for Figure 3 of the Paper

Lookup Values	
Total Deposition (kg/ha/yr) (1)	**Worst-Case Base Cation Concentration (μeq/L) (2)**
1.4	342

Notes:

(1) Total deposition is calculated as sulfur deposition plus 25% of nitrogen deposition. Individual sulfur and nitrogen deposition values in the calculation are taken from Tables 1 and 2 of this analysis.

(2) Worst-case base cation concentration corresponding to alkalinity of Emerald Lake analyzed by NDOW.

Figure 3 from the Paper is provided below, with points plotted for the Jarbidge lookup values and superimposed in blue. Since the point corresponding to Jarbidge falls to the right of all the safe lines in Figure 3, the predicted deposition levels for Jarbidge are not expected to have any adverse effects on plant or animal life in the aquatic ecosystems.

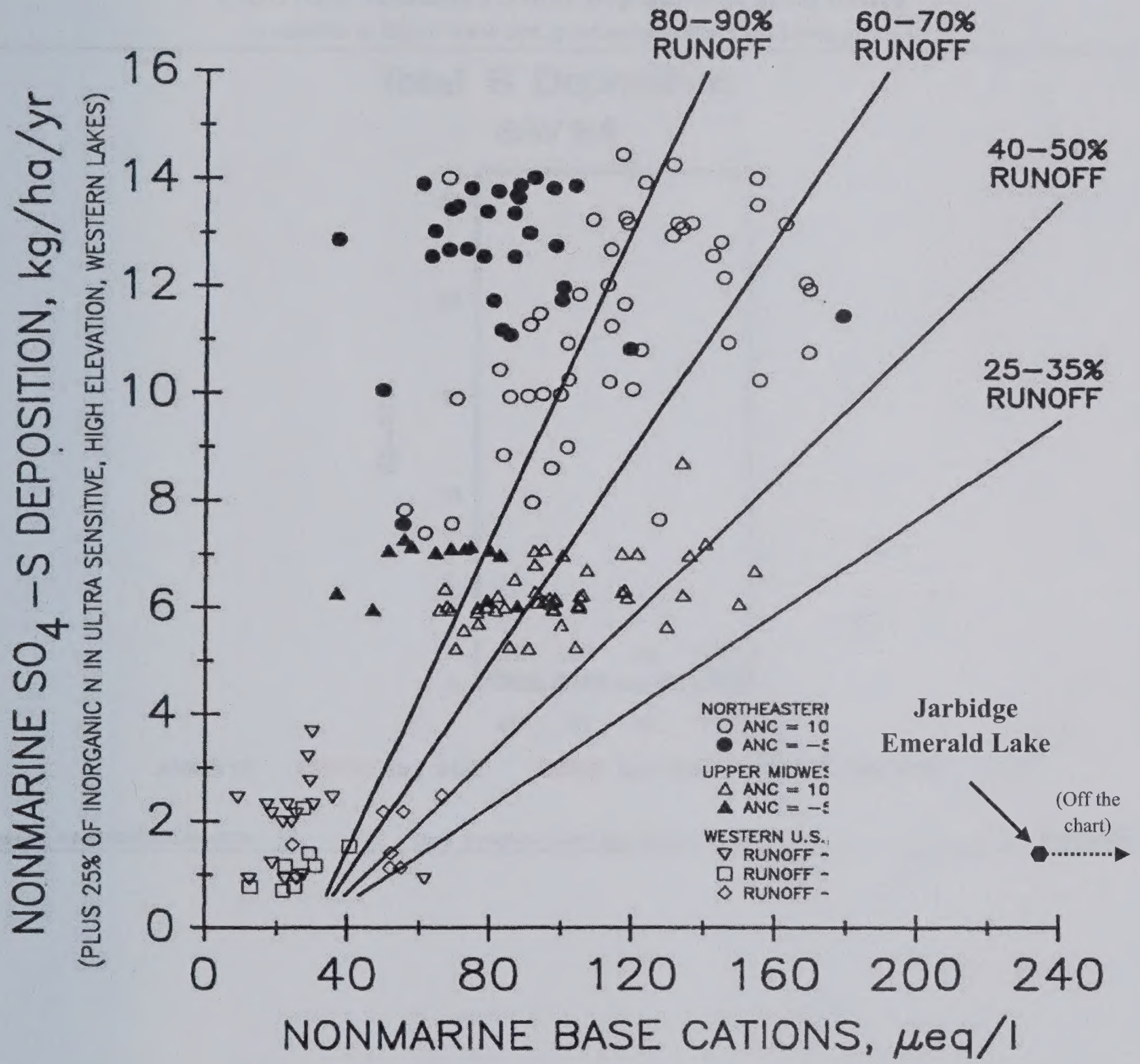
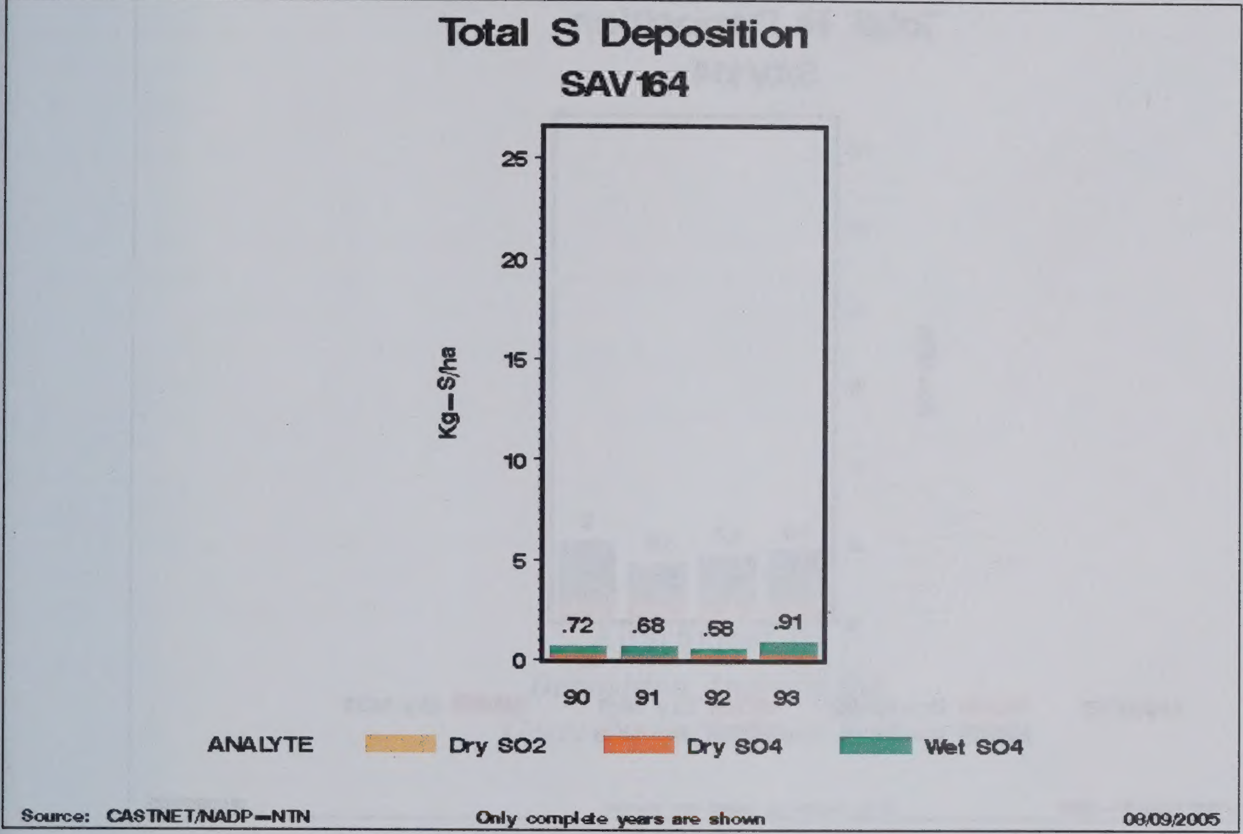


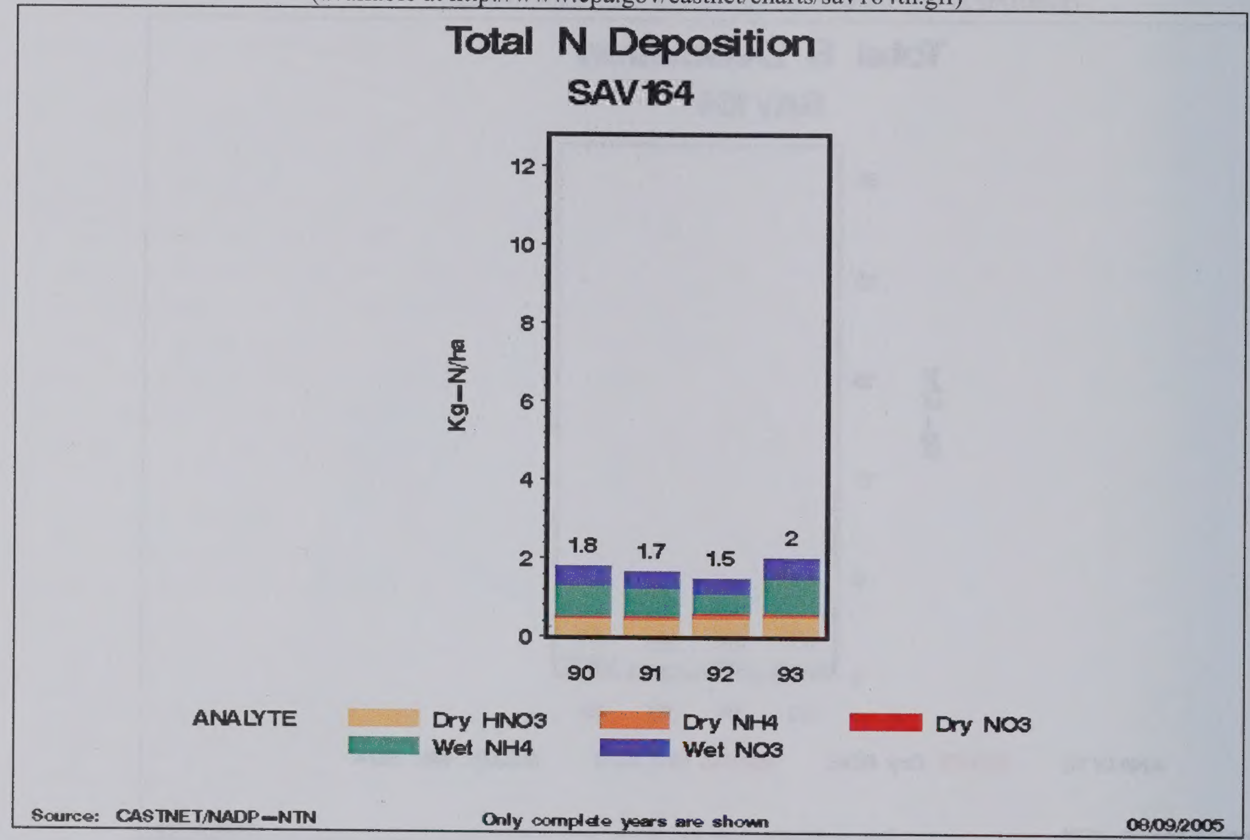
Figure 3.—*Base cations vs. deposition, "safe" lines. Lakes to the right of the appropriate runoff line are unlikely to be acidic. (Lake chemistry data from Kanciruk* et al. *1986 and Eilers* et al. *1987.)*

(Figure 3 from Nichols, Dale S., *Estimating Lake Susceptibility to Acidification Due to Acid Deposition,* United States Department of Agriculture Forest Service, Research Paper No. NC-289, February 1990.)

CASTNET Monitored Sulfur Deposition at Saval Ranch
(available at http://www.epa.gov/castnet/charts/sav164ts.gif)



CASTNET Monitored Nitrogen Deposition at Saval Ranch
(available at http://www.epa.gov/castnet/charts/sav164tn.gif)



Attachment 4B

Deposition Analysis for Great Basin National Park

Sulfur and Nitrogen Deposition

Cumulative Deposition Assessment - Great Basin National Park

The total deposition increases due to the WPES, the EEC, Toquop, Newmont, IPP3, and Nevco-Sevier, are evaluated in conjunction with EPA's Clean Air Status and Trends (CASTNET) monitored deposition values to demonstrate that aquatic ecosystems in the area would be safe from acidification effects after construction of the proposed action and the reasonably expected future actions. Predicted total deposition increases are presented below, along with actual monitored values applicable to Great Basin from the CASTNET monitoring network.

Table 1. Sulfur Deposition in the Great Basin Class II Area

Total S Deposition Increase (kg/ha/yr) (1)	CASTNET Monitored Existing S Deposition (kg/ha/yr) (2)	Total Predicted S Deposition (kg/ha/yr)
0.14	0.77	0.91

Notes:
(1) Total predicted sulfur deposition due to the WPES, EEC, Toquop, Newmont, IPP3, and Nevco-Sevier calculated in Attachment 1. Maximum deposition due to the WPES occurred during 1996; thus, background deposition values for 1996 were used.

(2) Site-specific deposition charts are included on the following pages.

Table 2. Nitrogen Deposition in the Great Basin Class II Area

Total N Deposition Increase (kg/ha/yr) (1)	CASTNET Monitored Existing N Deposition (kg/ha/yr) (2)	Total Predicted N Deposition (kg/ha/yr)
0.06	2.1	2.16

Notes:
(1) Total predicted nitrogen deposition due to the WPES, EEC, Toquop, Newmont, IPP3, and Nevco-Sevier calculated in Attachment 1. Maximum sulfur deposition due to the WPES occurred during 1996; thus, background deposition values for 1996 were used.

(2) Site-specific deposition charts are included on the following pages.

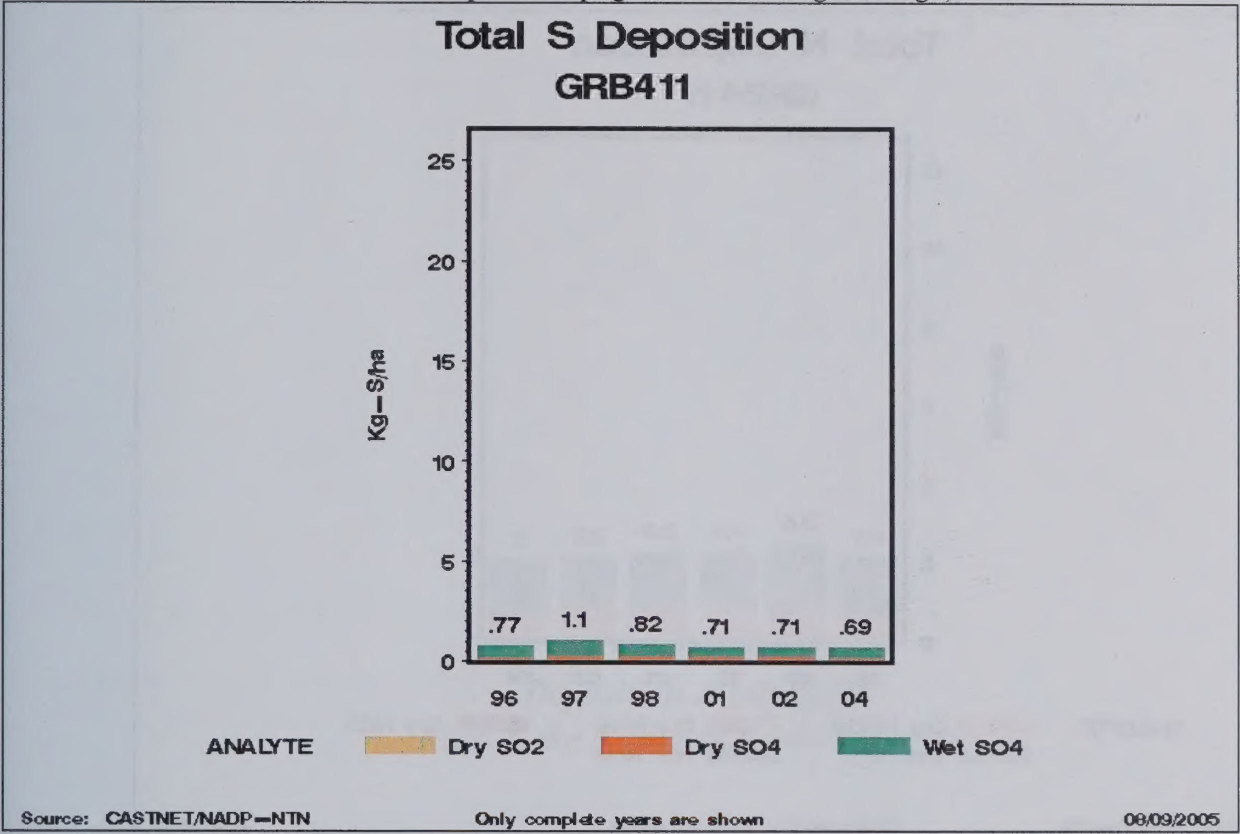
The USDA Forest Service research paper *Estimating Lake Susceptibility to Acidification Due to Acid Deposition* (the Paper) provides a procedure for predicting acid deposition effects on aquatic ecosystems. Figure 3 of the paper represents "safe lines" on a plot of deposition vs. base cation concentration. Lakes that fall on the right side of the "safe lines" are not expected to be adversely affected by the corresponding deposition levels. The Figure 3 "lookup" values corresponding to Great Basin are discussed below.

Sulfur and Nitrogen Deposition

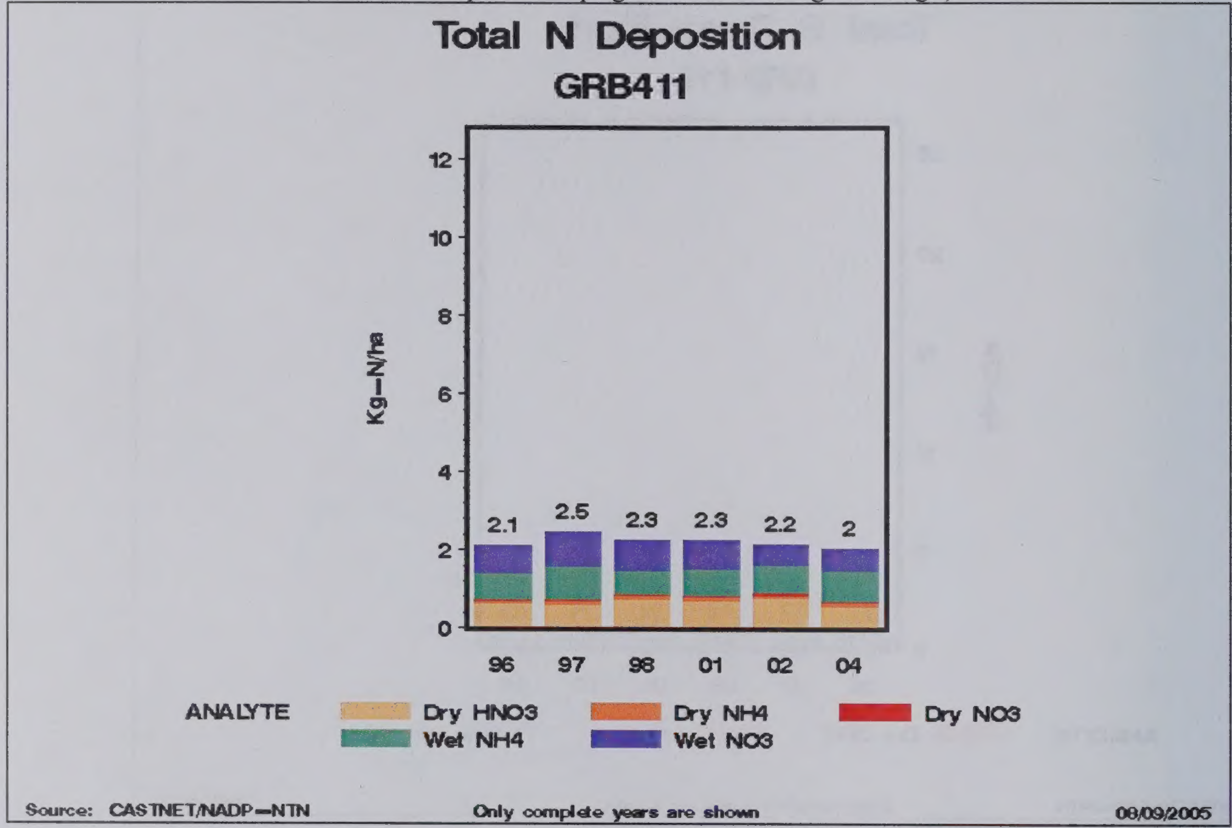
Cumulative Deposition Assessment - Great Basin National Park

CASTNET Monitored Sulfur Deposition at Great Basin

(available at http://www.epa.gov/castnet/charts/grb411ts.gif)



CASTNET Monitored Nitrogen Deposition at Great Basin
(available at http://www.epa.gov/castnet/charts/grb411tn.gif)



Attachment 4C

Deposition Analysis for Ruby Lake National Wilderness Area

Sulfur and Nitrogen Deposition

Cumulative Deposition Assessment - Ruby Lake National Wildlife Refuge

The total deposition increases due to the WPES, the EEC, Toquop, Newmont, IPP3, and Nevco-Sevier, are evaluated in conjunction with EPA's Clean Air Status and Trends (CASTNET) monitored deposition values to demonstrate that aquatic ecosystems in the area would be safe from acidification effects after construction of the proposed action and the reasonably expected future actions. Predicted total deposition increases are presented below, along with representative existing deposition values applicable to Ruby Lake from the CASTNET monitoring network.

Table 1. Sulfur Deposition in the Ruby Lake Class II Area

Total S Deposition Increase (kg/ha/yr) (1)	CASTNET Monitored Existing S Deposition (kg/ha/yr) (2)	Total Predicted S Deposition (kg/ha/yr)
0.03	0.71	0.74

Notes:
(1) Total predicted sulfur deposition due to the WPES, EEC, Toquop, Newmont, IPP3, and Nevco-Sevier calculated in Attachment 1. Maximum deposition due to the WPES occurred during 2001; thus, background deposition values for 2001 were used.

(2) Deposition measured at Great Basin National Park is considered representative of Ruby Lake due to the relative proximity of these two sites. Deposition charts for Great Basin are included in Attachment 3B of this white paper.

Table 2. Nitrogen Deposition in the Ruby Lake Class II Area

Total N Deposition Increase (kg/ha/yr) (1)	CASTNET Monitored Existing N Deposition (kg/ha/yr) (2)	Total Predicted N Deposition (kg/ha/yr)
0.01	2.2	2.21

Notes:
(1) Total predicted nitrogen deposition due to the WPES, EEC, Toquop, Newmont, IPP3, and Nevco-Sevier calculated in Attachment 1. Maximum sulfur deposition due to the WPES occurred during 2001; thus, background deposition values for 2001 were used.
(2) Deposition measured at Great Basin National Park is considered representative of Ruby Lake due to the relative proximity of these two sites. Deposition charts for Great Basin are included in Attachment 3B of this white paper.

The USDA Forest Service research paper *Estimating Lake Susceptibility to Acidification Due to Acid Deposition* (the Paper) provides a procedure for predicting acid deposition effects on aquatic ecosystems. Figure 3 of the paper represents "safe lines" on a plot of deposition vs. base cation concentration. Lakes that fall on the right side of the "safe lines" are not expected to be adversely affected by the corresponding deposition levels. The Figure 3 "lookup" values corresponding to Ruby Lake are discussed below.

Sulfur and Nitrogen Deposition

Cumulative Deposition Assessment - Ruby Lake National Wildlife Refuge

In high elevation Western lakes, both sulfur and nitrogen deposition can contribute to aquatic acidity. For such lakes, the Paper indicates that the total deposition used as a "lookup" value in Figure 3 should include all sulfur deposition, plus 25% of the nitrogen deposition to account for the acidification potential of inorganic nitrogen. (Although the elevation of Ruby Lake, approximately 6,000 feet, may be lower than other western lakes considered "high-elevation," the high-elevation lake evaluation methods are used to ensure a conservative analysis.)

The US Fish & Wildlife Service identified the Ruby Lake South Marsh as a potentially sensitive area with respect to acid deposition. Recent sampling at the South Marsh indicates the base cations concentration at the South Marsh is 7,511 μeq/L. The "lookup" values for Figure 3 of the Paper are provided in Table 3 below.

Table 3. Lookup Values for Figure 3 of the Paper

Lookup Values	
Total Deposition (kg/ha/yr) (1)	**Base Cation Concentration (μeq/L) (2)**
1.3	7,511

Notes:
(1) Total deposition is calculated as sulfur deposition plus 25% of nitrogen deposition. Individual sulfur and nitrogen deposition values in the calculation are taken from Tables 1 and 2 of this analysis.
(2) Base cation concentration at the South Marsh determined by recent testing.

Figure 3 from the Paper is provided below, with points plotted for the Ruby Lake lookup values and superimposed in blue. Since the point corresponding to Ruby Lake falls to the right of all the safe lines in Figure 3, the predicted deposition levels for Ruby Lake are not expected to have any adverse effects on plant or animal life in the aquatic ecosystems.

Sulfur and Nitrogen Deposition

Cumulative Deposition Assessment - Ruby Lake National Wildlife Refuge

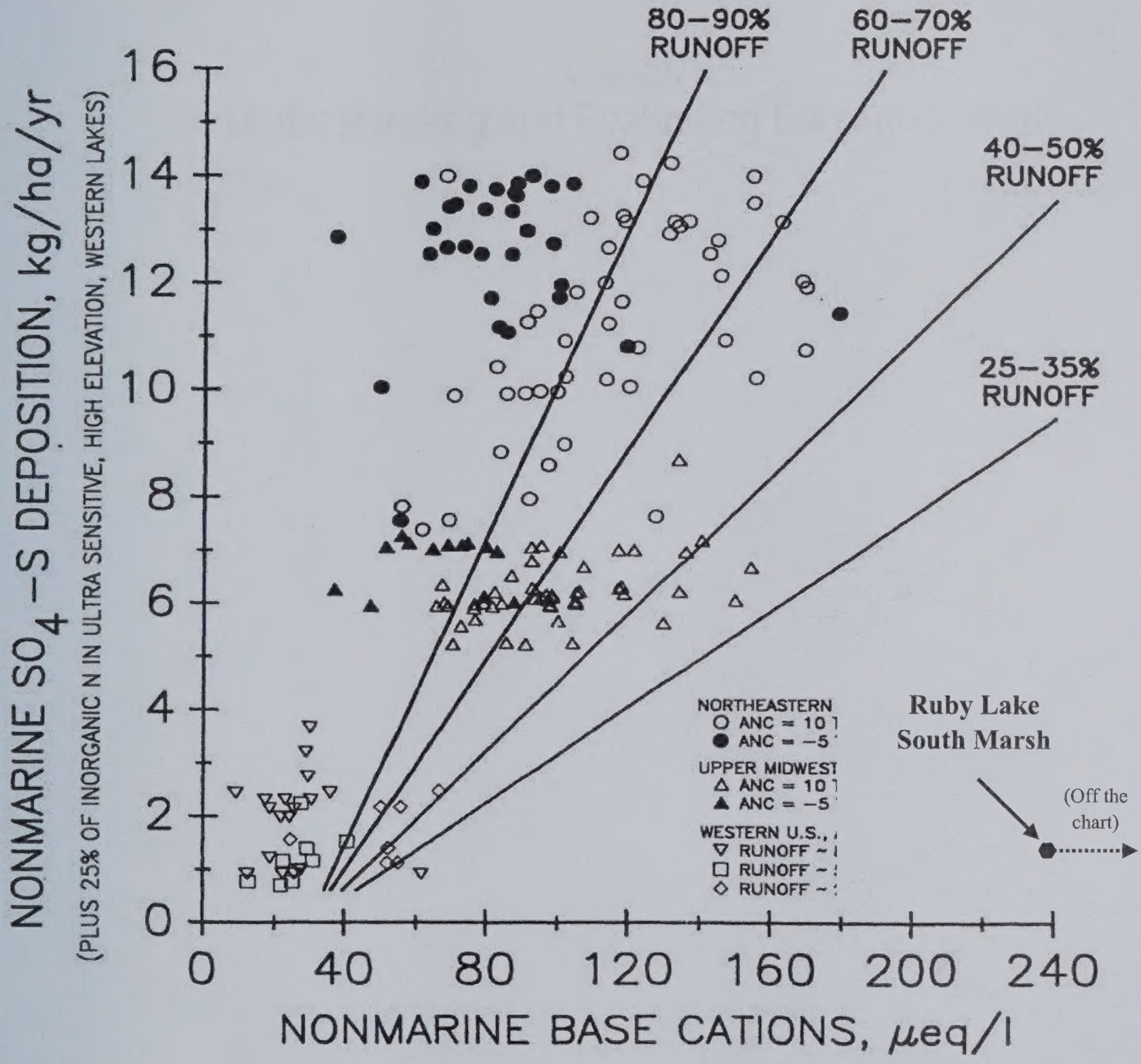


Figure 3.—*Base cations vs. deposition, "safe" lines. Lakes to the right of the appropriate runoff line are unlikely to be acidic. (Lake chemistry data from Kanciruk* et al. *1986 and Eilers* et al. *1987.)*

(Figure 3 from Nichols, Dale S., *Estimating Lake Susceptibility to Acidification Due to Acid Deposition,* United States Department of Agriculture Forest Service, Research Paper No. NC-289, February 1990.)

Appendix M

Understanding and Evaluating Climate Change

Report

Understanding and Evaluating Climate Change

Prepared by

U.S. Bureau of Land Management

Ely Field Office, Nevada

Contents

Acronyms and Abbreviations

AR4	Fourth IPCC Assessment Report
C	Celsius
CCS	CO_2 Capture and Storage
CFCs	Chlorofluorocarbons
CH_4	Methane
CO_2	Carbon Dioxide
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
F	Fahrenheit
FAR	First IPCC Assessment Report
GHG	Greenhouse Gases
GW/CC	Global Warming/Climate Change
GWP	Global Warming Potential
Halons	Halocarbons containing bromine
HCFCs	Hydrochlorofluorocarbons
HFCs	Hydrofluorocarbons
IPCC	Intergovernmental Panel on Climate Change
MW	Megawatt
NCDC	National Climate Data Center
N_2O	Nitrous oxide
NO_x	Nitrates
O_3	Ozone
PFCs	Perfluorocarbons
PPM	Parts Per Million
PM	Particulate Matter
RF	Radiative Forcing
SAR	Second IPCC Assessment Report
SCC	Social Cost of Carbon
SF_6	Sulfur Hexafluoride
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
WMO	World Meteorological Organization

1. Introduction

Information provided here summarizes current studies by the Intergovernmental Panel on Climate Change (IPCC) and from other peer-reviewed publications. The primary conclusions and projections regarding future climate change are drawn from IPCC. The growing level of international attention to Global Warming/climate Change (GW/CC) has resulted in a high level of ongoing scientific study and analysis. The body of scientific knowledge of the issue is evolving relatively rapidly. The information contained herein may become out-dated quickly, but serves as a "snapshot" of the state-of-knowledge at the time of the analyses conducted under this EIS. The reports referenced herein, and any subsequent reports provided by IPCC or other governmental bodies, should be consulted for more detailed or the most up-to-date information.

1.1 Climate Change Overview

A growing body of evidence indicates that Earth's atmosphere is warming. Records show that surface temperatures have risen about 0.7°C since the early 20th century and that 0.5°C of this increase has occurred since 1978 (National Academies of Sciences [NAS], 2006a summary, U.S. Global Change Research Program [USGRP], 2001). Observed changes in oceans, snow and ice cover, and ecosystems are consistent with this warming trend (NAS, 2006a; IPCC, 2001; 2007).

Earth's climate has exhibited variability and has changed over time. The extremes of the 100,000-year ice age cycles and interglacial periods have been well documented. The period of the last 10,000 years has been generally warm and stable. Observations in the 20th century indicate rapid climate change (IPCC, 2001; 2007; NAS, 2006a). The National Academy of Sciences (2006b) recently supported the conclusion that it is likely that the past few decades exhibited higher global mean surface temperatures than during any comparable period of the preceding four centuries. Additionally, 11 years between 1995 and 2006 rank among the 12 warmest years in the instrumentation record (1850 to 2006) for global surface temperature (IPCC, 2007).

1.2 Definitions

In common terms, one can think of "climate" as the "average weather" conditions over some extended period. The IPCC (2001) provides a more rigorous definition of climate as the "statistical description in terms of the mean and variability of relevant parameters over a period of time ranging from months to thousands or millions of years." Parameters measured are most often surface variables such as temperature, precipitation, and wind. Data are typically averaged in 30-year periods as defined by the World Meteorological Organization. "Climate change" is the shift in the average weather, or trend, that a region experiences. Thus, climate change cannot be represented by single annual events nor individual anomalies. That is, a single large flood event or particularly hot summer is not an

indication of climate change, while a series of floods or warm years that statistically change the average precipitation or temperature over time may indicate climate change.

The IPCC (2004) provides the following definition for climate change: Climate change refers to a statistically significant variation in either the mean state of the climate or in its variability, persisting for an extended period (typically decades or longer).

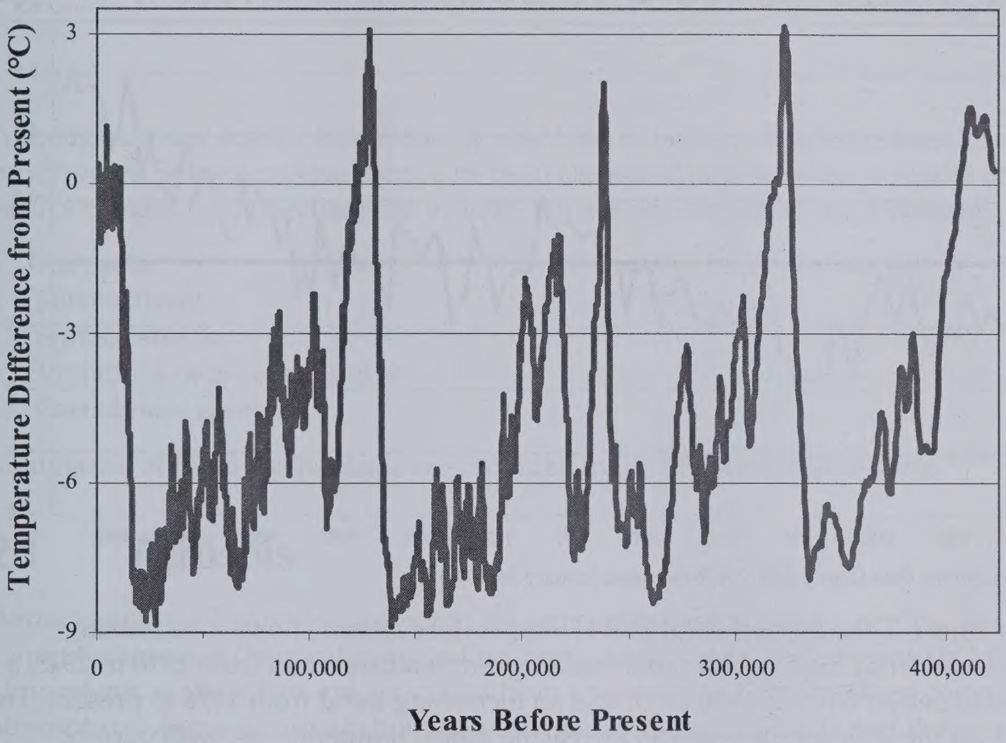
"Climate variability," refers to the deviation from the average climate. For example, an individual year that is drier or hotter than average would indicate variability, but may not indicate a shift in the trend as would be defined as climate change.

1.3 Paleoclimate

Studies of the earth's climate in the past (paleoclimate) provide a context for understanding current and future climate variability. Various "proxy" parameters, such as tree rings, ice cores, sea sediments, and geologic observations, have been studied to provide estimates of the earth's temperature over time. Studies of proxy data have revealed long periods with temperatures both much cooler and much warmer than present day. For example, portions of the Neoproterozoic Era (750 million and 600 million years ago), have been referred to as "snowball earth" periods because much of the Earth was covered by ice. Conversely, several periods within the Phanerozoic Era (the past 600 million years) have been noted as warm periods, including the middle Pliocene (3 million years ago), the Late Paleocene (58 million years ago), the Paleocene-Eocene Thermal Maximum (55 million years ago), the Cretaceous (130 to 65 million years ago), and the Early Jurassic (180 million years ago) (NASA, 2007b).

The recent Pleistocene Epoch (from 1.8 million years to 11,550 years before present) was a period of recurring and widespread glaciations (ice ages, or periods of glacial expansion), with almost one-third of the present land surface area intermittently covered by ice. Warm periods between glaciations are known as interglacial periods. The most recent glaciation reached its peak approximately 20,000 years ago, with a major ice sheet spreading across the North Central United States as far south as Central Illinois (USGS, 1992). This ice age subsided with the onset of the current warm interglacial period, known as the Holocene Epoch. Figure 1 shows a temperature record for the past 420,000 years, reconstructed from ice cores drilled at Vostok Station, located near the center of the East Antarctic ice sheet.

FIGURE 1
Vostok Ice Core Temperatures, Past 420,000 Years



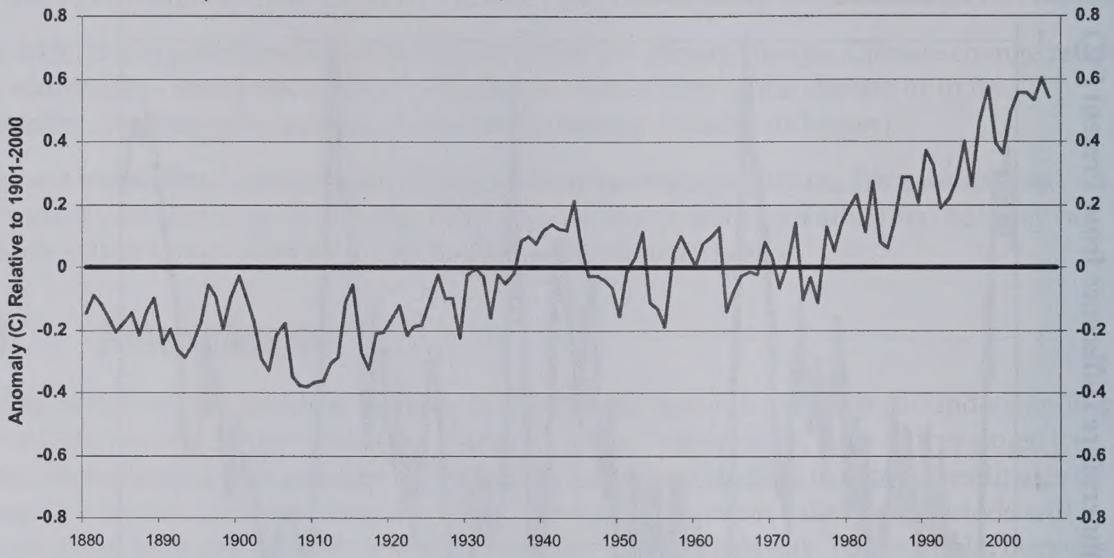
Source: Petit, J.R., et al., 2001

Although warm in comparison with the average climate over the Pleistocene Epoch, the current Holocene Epoch has exhibited periods both warmer and cooler than present day. The Holocene maximum was a period of warm temperatures approximately 3,000 years in duration that occurred 6,000 years before present. A shorter warm period, known as the Medieval warm period, occurred around 1000 AD and lasted for approximately 350 years. After the Medieval warm period, the Little ice age began around 1500 AD and lasted for approximately 300 years. After the Little ice age, both the proxy records and the instrumental temperature records indicate warming starting during the 20th century.

1.4 Recent Observations of Climate Change

The earliest records of temperature measured by thermometers are from western Europe beginning in the late 17th and early 18th centuries. The network of temperature collection stations increased over time. By the early 20th century, records were being collected in almost all regions except for polar regions where collections began in the 1940s and 1950s (National Climate Data Center (NCDC), 2007a). As with other periods in the earth's history, the period of instrumental temperature records shows both increases and decreases in global temperature. The changes in global temperature during the period of instrumental record are shown in Figure 2. The term "temperature anomaly" refers to the difference between the observed temperature and the 20th century average temperature.

FIGURE 2
Global Annual Mean Temperature Over Land and Ocean, 1880 to 2007



Source: National Climatic Data Center data, 2007b (accessed January 16, 2008)

As shown in Figure 2, the instrumental global temperature record shows a decreasing temperature trend from 1880 to 1909; an increasing temperature trend from 1910 to 1945; a relatively stable period from 1946 to 1975; and an increasing trend from 1976 to present. The overall trend for the 20th century reflects increasing global temperatures, with current global temperatures approximately 0.6°C above the 20th century average. Over the past century, global surface temperatures have increased at an average rate of approximately 0.05°C per decade, with higher rates of approximately 0.15°C per decade for the periods from 1910 to 1945 and 1976 to 2007 (NCDC, 2007b).

2. Potential Causes of Climate Change

Although climate science is a relatively new field of inquiry, much has been learned in recent years. Several mechanisms have been identified that have the potential to affect the earth's climate. Such mechanisms include, but are not limited to, the following:

- Aerosols
- Solar activity
- Surface albedo
- Variations in the earth's orbit
- Greenhouse gases

Summaries of these mechanisms are provided in the following subsections.

2.1 Aerosols

Aerosols are small particles present in the atmosphere with widely varying size, concentration, and chemical composition. Some aerosols are emitted directly into the atmosphere, while others are generated from chemical reactions between compounds in the atmosphere. Aerosols contain both naturally occurring compounds and those emitted as a result of human activities. Natural aerosols include mineral dust released from the surface, sea salt aerosols, biogenic emissions from the land and oceans, and sulfate and dust aerosols produced by volcanic eruptions (IPCC, 2007d, pp. 135-136, 2007). Human activities such as agricultural burning have also contributed to aerosol concentrations in the earth's atmosphere.

Although the aerosol forcing is not well-understood, aerosols are known to influence the earth's energy balance and resulting climate. The level of scientific understanding for the aerosol forcing is indicated as "medium to low" for the direct effect and "low" for the cloud albedo effect (IPCC, 2007e, Figure SPM.2, 2007). Aerosol particles influence radiative forcing directly through reflection and absorption of solar and infrared radiation in the atmosphere. In climate science, the term "radiative forcing" (expressed in W/m^2) refers to a disturbance in the balance between incoming radiant energy absorbed and outgoing radiant energy. This type of disturbance drives the earth's energy balance and resulting atmospheric temperature toward a new equilibrium (Masters, 1998). Some aerosols cause a positive forcing, while others cause a negative forcing. The direct radiative forcing summed over all aerosol types is believed to be negative. Additionally, aerosols are also believed to cause a negative radiative forcing indirectly through the changes they cause in cloud properties (IPCC, 2007d, p. 136). These indirect effects on clouds include the radiative properties, the amount, and lifetime of the clouds. In its AR4 report, the IPCC denotes the indirect aerosol effects as "cloud albedo effect" and "cloud lifetime effect" as these terms are more descriptive of the microphysical processes that occur (IPCC, 2007d, p. 153).

As mentioned in previous text, aerosols may be either natural or anthropogenic (human-caused) in origin. Volcanic eruptions are an important example of episodic natural aerosol

emissions. Explosive volcanic eruptions can create a short-lived (2 to 3 years) cooling forcing on the climate system through the temporary increases that occur in sulfate aerosol in the stratosphere. The IPCC also notes that the stratosphere is currently free of volcanic aerosol, since the last major eruption was in 1991 (Mount Pinatubo) (IPCC, 2007d, p. 137). Future volcanic eruptions are likely to influence global climate periodically. The degree of climate disruption resulting from these eruptions can be significant. For example, the proxy record indicates a volcano-induced northern hemisphere temperature decrease of 0.81°C in 1601, the year following the eruption of Huaynaputina in Peru (Briffa et al., 1998).

Anthropogenic aerosol emissions originate from a variety of sources (industry, transportation, agriculture, etc.). The IPCC estimates that anthropogenic aerosol emissions provide radiative forcings of -0.5 W/m^2 for the direct effect and -0.7 W/m^2 for the cloud albedo effect; thus, anthropogenic aerosol emissions are believed to exert a cooling influence on the earth's climate. This influence could increase or decrease in the future, depending on future changes in anthropogenic emissions.

2.2 Solar Activity

The sun is the earth's primary source of incoming energy; thus, solar activity is the most significant contributor to the earth's energy balance. The earth's energy balance includes a myriad of factors and is described briefly in the following text.

The magnitude of solar radiation at the outside of the earth's atmosphere is approximately 1,370 Watts per square meter (W/m^2). Averaged over the surface area of the earth, the incoming solar radiation is approximately 342 W/m^2. A portion of this incoming solar energy is reflected back into space by the atmosphere or the surface of the earth. This reflected energy fraction is called the "albedo," and for the earth is estimated to be approximately 31 percent. The remaining 69 percent of the incoming energy is absorbed by the atmosphere or the surface of the earth (Masters, 1998, pp. 464 and 470).

To maintain the earth's energy balance at steady-state conditions (constant temperature), all of the incoming solar energy must be radiated back into space (there is no heat transfer from the earth to space by conduction or convection). Because an object radiates heat at a rate proportional to the object's surface area times absolute temperature to the 4th power, it is possible to back-calculate the temperature (known as the ideal "blackbody temperature") required for the earth to radiate all the absorbed energy from the sun back into space. The earth's effective blackbody temperature is -19°C, a value less than the earth's average surface temperature of approximately 15°C (Masters, 1998, pp. 464 and 465). This 34°C discrepancy between the blackbody temperature and the actual temperature can be explained by the interaction between the outgoing radiation and the earth's atmosphere, a phenomenon known as the "greenhouse effect," as discussed in detail in the greenhouse gas Section 2.5.

Changes in solar energy output result in a forcing on the earth's energy balance and climate system. As discussed in the previous text, the energy balance for the earth is dictated by the amount of radiation received from the sun; thus, small variations in solar output can result in significant radiative forcings on the climate system. For example, solar output is known to follow an 11-year cycle in which solar irradiance varies by 0.1 percent (Dima et al., 2005).

A change in solar irradiance of 0.1 percent would result in a direct solar radiative forcing on the climate system of 0.3 W/m^2. Additional known and unknown feedback mechanisms have the potential to significantly amplify this forcing, and such feedbacks have been suggested by recent research. For example, Scafetta and West (2006) have recently shown that observed feedbacks associated with past changes in solar activity have resulted in radiative forcings greater than those predicted by climate models and that "most of the sun-climate coupling mechanisms are probably still unknown." The magnitude of these solar-associated forcings is such that "the amplitude of the 11-year solar signature on the temperature record seems to be three times larger than theoretical predictions." The conclusions of this research regarding solar-associated feedback mechanisms are consistent with recent findings by Douglass and Clader (2002), Bond, et al. (2001), and Chambers, et al. (1999).

Consistent with the findings of significant climate feedbacks in response to changes in solar activity, recent research suggests that changes in solar irradiance are responsible for a significant portion of the warming observed during the 20th century. For example, Willson and Mordinov have shown that solar irradiance, during times of quiet sunspot activity, has increased by 0.05 percent per decade between 1978 and 2003 (Willson and Mordvinov, 2003). According to Willson and Mordinov, "this trend is important because, if sustained over many decades, it could cause significant climate change" (Willson and Mordvinov, 2003). Beer, et al. (2000) conclude that changes in solar irradiance are responsible for approximately 40 percent of the global warming observed in the last 140 years. Additionally, findings by Scafetta and West suggest the presence of a solar cycle driving the climate of the last millennium, with maximum solar irradiance occurring during the medieval period and at present day (Scafetta and West, 2006). Scafetta and West further estimate that the sun has contributed as much as 45 to 50 percent of the warming observed from 1900 to 2000 (Scafetta and West, 2006). Thus, variations in solar activity are an important factor in the earth's climate (including recent climate change) and continue to be the subject of ongoing climate research.

2.3 Surface Albedo

As discussed in the previous text, the earth's albedo refers to the fraction of incoming solar energy that is reflected back into space by the atmosphere or by the surface of the earth. By reflecting incoming energy, reflective surfaces increase the earth's average albedo and thereby exert a cooling influence on the earth's climate. Conversely, surfaces that tend to absorb energy instead of reflecting it decrease the earth's average albedo and exert a warming influence on climate. The earth's surface albedo constantly changes because of both natural (for example, leaf growth during the springtime) and anthropogenic (for example, agricultural land use) surface influences.

Because natural changes in surface albedo are believed to occur over long timescales, anthropogenic changes are those typically studied with respect to climate change. Two primary types of anthropogenic surface albedo changes are land cover changes and black carbon deposition. Land cover changes, largely resulting from net deforestation, have increased the surface albedo, creating an estimated radiative forcing of minus 0.2 W/m^2, with a medium-low level of scientific understanding. Black carbon aerosol deposited on

snow has reduced the surface albedo, producing an associated radiative forcing of +0.1 W/m^2, with a low level of scientific understanding. Other surface property changes can affect climate through processes that cannot be quantified by radiative forcing, and the level of scientific understanding of these phenomena is very low (IPCC, 2007d, p. 132). Changes in surface albedo are expected to continue to occur in the future, with unknown effects on net radiative forcing.

2.4 Variations in the Earth's Orbit

Independent of any variations in solar output, variations in the earth's orbit affect the distribution and intensity of incoming solar radiation and therefore affect the earth's energy balance and resulting climate. The connection between climate and orbital variations were proposed in the 1930s by astronomer Milutin Milankovitch. The effects of the earth's orbital cycles on climate have become known as "Milankovitch oscillations" (Masters, 1998, p. 460). The three primary orbital cycles are as follows:

- Eccentricity—the oscillation in the earth's orbit from elliptical to nearly circular with a period of 100,000 years
- Obliquity—the tilt angle with respect to the earth's orbit, fluctuating from 21.5° to 24.5° with a period of 41,000 years
- Precession—the "wobble" of the earth's spin axis with a period of 23,000 years Masters 1998, p. 460-461)

The historical proxy record reveals that the orbital cycles have impacted the glacial-interglacial cycle during the Pleistocene. The primary glacial-interglacial cycle is approximately 100,000 years, with secondary oscillations with periods of 23,000 and 41,000 years, approximately matching the Milankovitch theory. While these orbital variations only changed the incoming solar energy by about 0.1 percent, the resulting global impacts are thought to be significant enough to trigger major changes in climate (to drive the cycle of ice ages) (Masters, 1998, p. 461-462). The IPCC summarizes this concept by stating that "[r]egular variation in the Earth's orbital parameters has been identified as the pacemaker of climate change on the glacial to interglacial time scale (see Berger, 1988 for a review). These orbital variations, which can be calculated from astronomical laws (Berger, 1978), force climate variations by changing the seasonal and latitudinal distribution of solar radiation (Chapter 6)" (IPCC, 2007d, p. 673).

Although variations in the earth's orbit are not believed to contribute to the warming observed since 1900, these variations have clearly contributed to climate changes in the past and will continue to do so in the distant future. Additionally, the response of the glacial-interglacial cycle to small changes in the amount of solar energy input brought on variations in the earth's orbit reinforces the climate's sensitivity to small changes in the solar forcing.

2.5 Greenhouse Gases

2.5.1 Historic Study of Greenhouse Gases

Joseph Fourier is credited with the discovery in 1824 that gases in the atmosphere might increase the surface temperature of the Earth. Fourier referred to an experiment by M. de Saussure, who exposed a black box to sunlight; he noted that when a thin sheet of glass is put on top of the box, the temperature inside of the box increases. In 1859 John Tyndall identified several gases that could trap heat waves, specifically water vapor and carbon dioxide (CO_2) (Weart, 2007).

During the 1950s, discovery of the radioactive isotope carbon-14 enabled scientists to distinguish fossil carbon in the atmosphere. Measurements of carbon in the atmosphere in conjunction with calculations estimating the carbon being taken up by the oceans led to the realization that although sea water did rapidly absorb CO_2, most of the added gas would promptly evaporate back into the air. By the late 1950s, a few scientists began to warn that greenhouse warming might become a problem, even within the foreseeable future (Weart, 2007).

In the late 1950s and early 1960s, a baseline level of CO_2 measured in the atmosphere of Antarctica and the Mauna Loa volcano in Hawaii established that the level of CO_2 in the atmosphere was rising. The baseline data supported the theory that the oceans were not taking up most industrial emissions. Through the 1960s, interdisciplinary sharing of information resulted in the first reasonably solid estimate of the global temperature change that was likely if the amount of CO_2 in the atmosphere doubled. However, the scientific community continued to persist with the assumption that "…the Earth's geochemistry was dominated by stable mineral processes, operating on a planetary scale over millions of years." (Weart, 2007) The debate continued into the 1970s; the veracity of old data was questioned, and historical temperature shifts could not be tied to CO_2 levels in the atmosphere, casting doubt on theories connecting human activity with CO_2 levels in the atmosphere and possible climactic effects. By the end of the 1970s, however, measurements of CO_2 levels in the atmosphere showed a clear rise, global temperatures began to rise again, and computer models were resulting in agreement on the future warming to be expected from increased CO_2 (Weart, 2007).

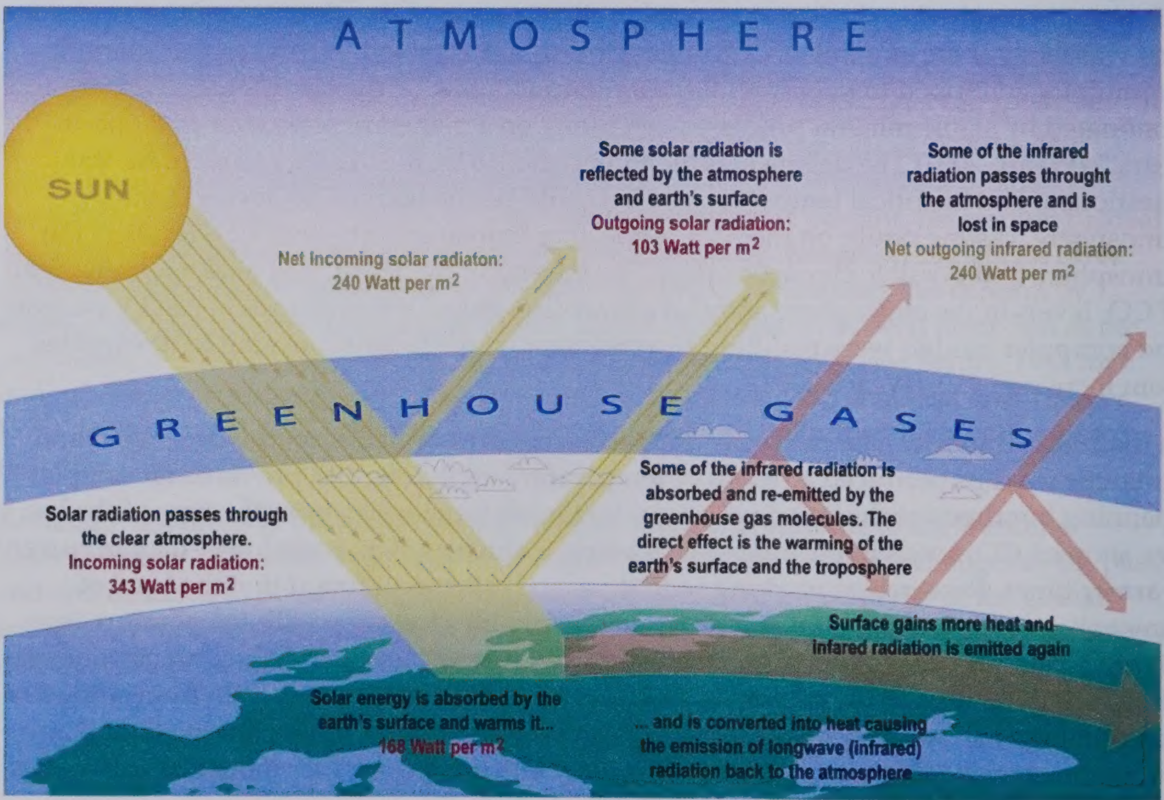
In the 1980s, chemical analysis of air trapped in ice cores drilled from the Greenland and Antarctic ice caps produced a record of temperature variations and provided air samples spanning hundreds of thousands of years. Testing of ice samples from the time of the last ice age showed CO_2 levels in the atmosphere were as much as 50 percent lower than in current warmer times. Researchers working with these and other data found that the level of atmospheric CO_2 had gone up and down in remarkably close step with temperature (see Figure 4 below). The modern air above the ice had reached levels of CO_2 concentrations far above anything seen in the geological era represented in the ice cores. Data from studies of paleontology and water temperatures in ocean basins mirrored trends linking temperature fluctuations with CO_2 concentrations, ultimately affirming computer modeling techniques (Weart, 2007).

2.5.2 The Greenhouse Effect (Science/Process)

The energy from the Sun powers the natural systems on earth. Energy is emitted from the Sun in the form of short wavelengths such as light and other electromagnetic rays. However, shortwave energy is not sensible (sensation of heat). Of the shortwave energy that reaches the Earth's atmosphere from the Sun, approximately one-third is reflected back into space, while the remaining two-thirds reaches the Earth's surface or is absorbed by the Earth's atmosphere. Shortwave energy reaching the earth's surface is either absorbed by the Earth or reflected back into the atmosphere (Le Treut et al., 2007). This process is depicted in Figure 3.

To balance the absorbed incoming energy, the Earth must, on average, radiate the same amount of energy back to space. Because the Earth is much colder than the Sun, it radiates at much longer wavelengths, primarily in the infrared part of the spectrum. Much of this thermal radiation emitted by the land and ocean is absorbed by the atmosphere, including clouds, and reradiated back to Earth. This is called the greenhouse effect. The Earth's greenhouse effect warms the surface of the planet (Le Treut et al., 2007). Without the natural greenhouse effect, the average temperature at Earth's surface would be approximately 34°C colder. The greenhouse effect creates a climate on Earth that is conducive to life. Therefore, the greenhouse effect is a natural process, upon which life on Earth depends.

FIGURE 3
The Greenhouse Effect (adapted from NAS, 2006a)



The two primary gases in the atmosphere responsible for the greenhouse effect are water vapor and CO_2. Methane, nitrous oxide, ozone and several other gases present in the

atmosphere in small amounts also contribute to the greenhouse effect (Le Treut et al., 2007). Taken together, these are referred to as "greenhouse gases." In addition to reflecting the Sun's energy back into space, greenhouse gases also control the amount of heat radiated by the Earth that is trapped beneath the atmosphere. Fluctuations in greenhouse gases in the atmosphere are partially responsible for variances in the Earth's climate along with other influences. The concentrations of these gases in the atmosphere are affected by complex natural systems that tend to either emit or sequester these gases. Man-made (anthropogenic) influences and emissions also affect the prevalence of these gases in the atmosphere, particularly CO_2 which has been emitted in relatively large and growing quantities since the dawn of the Industrial Revolution when coal and later petroleum were burned for energy.

The ability of gases to absorb radiant energy from the earth is the key phenomena of interest in studying the greenhouse effect. Different gases absorb and radiate energy at specific wavelengths. Radiatively active gases that absorb wavelengths longer than 4 microns (long-wavelength radiation emitted by the earth) are called "greenhouse gases." The primary greenhouse gases include water vapor, CO_2, CH_4, N_2O, and O_3 (Masters, 1998, p. 467). Water vapor is the most important greenhouse gas (IPCC, 2007d, p. 115), contributing approximately 90 percent of the total greenhouse heating (U.S. Energy Information Administration, 1994; Ramanathan and Coakley, 1978; Newell and Dopplick, 1979). Because the infrared absorption bands of the various greenhouse gases overlap, the contributions from individual absorbers do not add linearly. For example, CO_2 would be capable of contributing up to 36 percent of greenhouse heating if no other greenhouse gases were present. However, because of the presence of other greenhouse gases with absorption spectra overlapping that of CO_2 (for example, water vapor), only about 12 percent of greenhouse effect heating would be removed if CO_2 were removed from the atmosphere entirely (U.S. Energy Information Administration 1994). Because of the total heating effect of all greenhouse gases, the earth's temperature averages approximately 15°C, instead of the ideal blackbody temperature of minus 19°C.

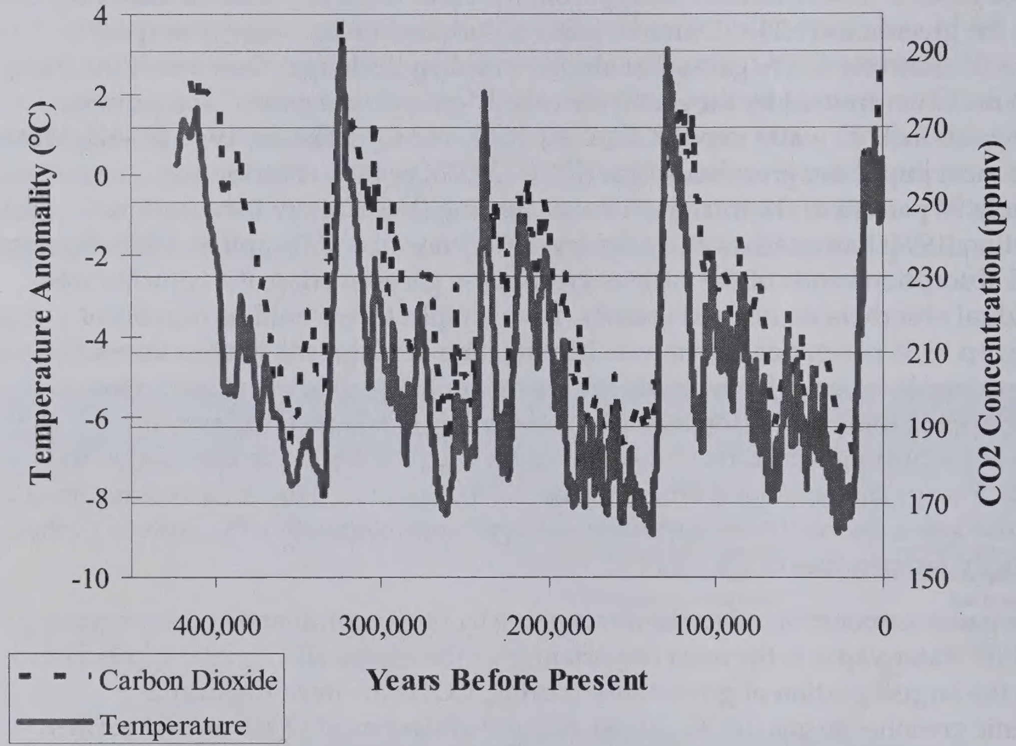
Greenhouse gases are contributed to the atmosphere by both natural and anthropogenic sources. While water vapor is the most important greenhouse gas (IPCC, 2007d, p 115) and contributes the largest portion of greenhouse heating, CO_2 is the most important anthropogenic greenhouse gas (IPCC, 2007e). Natural emissions of CO_2 from the earth's soils, vegetation, and ocean make up the vast majority of CO_2 emissions to the atmosphere. Anthropogenic CO_2 emissions from fossil fuel combustion are also a significant source of CO_2 emissions to the atmosphere, comprising 3 percent of the total global gross emissions of CO_2 (IPCC, 2007d, p. 514-515, Figure 7-3). The net CO_2 fluxes to and from the atmosphere, when averaged over decades or longer, are believed to have been in balance prior to 1750. Concerns have arisen in recent years that anthropogenic CO_2 emissions could contribute to a positive forcing on the earth's climate system, thereby influencing climate.

Fluctuations in greenhouse gas concentrations have occurred throughout the course of the earth's history. A variety of scientific studies have been conducted to evaluate the impacts of changes in CO_2 concentration on the earth's climate. One such study by Rothman (2002) evaluated CO_2 concentrations over the last 500 million years and found that CO_2 levels have generally decreased for the last 175 million years. Prior to that time, CO_2 levels appear to have fluctuated from about two to four times modern levels. The Rothman study concludes that variations in CO_2 levels exhibit "no systematic correspondence with the geologic record

of climatic variations at tectonic time scales." Over the most recent 60 million years, CO_2 concentrations in the atmosphere have typically been higher than present (but decreasing overall), with multiple periods where CO_2 levels were approximately 3 to 10 times present-day levels (IPCC, 2007d, p. 441).

Over the period of record for the Vostok ice cores (approximately the past 420,000 years), CO_2 concentrations and temperature have correlated closely during the last several glacial-interglacial cycles. Figure 4 shows the trends in temperature and CO_2 concentration based on the Vostok ice core data.

FIGURE 4
Temperature and CO_2 Concentration



Source: Petit, J.R., et al., 2001

As shown in Figure 4, temperature and CO_2 concentrations have followed the same trends over the past 420,000 years; however, a statistical analysis of the data indicates that CO_2 did not initiate the changes in temperature trends during this period. Mudelsee (2001) evaluated the CO_2/temperature data from the Vostok ice cores and determined that variations in CO_2 concentration lag behind those of the temperature record by an average of 1,300 years. These findings indicate that during the 420,000 years of the Vostok ice core record, the warming trends began first, followed by increasing CO_2 concentrations an average of 1,300 years later. Variations in the eccentricity of earth's orbit around the sun, with longer periodicities at 400,000 and 100,000 years, also correspond to the cycle of glacial-interglacial periods. However, the variations in the earth's orbit are not believed to contribute to the warming observed since 1900.

3. Anthropogenic Contributions of Greenhouse Gases

Anthropogenic CO_2 emissions have increased from low levels in pre-industrial times (prior to 1750) to approximately 36,000 million tons (36 billion tons) per year at present day (IPCC, 2007e, p 2-3). The majority of anthropogenic CO_2 emitted to the atmosphere, approximately 80 percent, is released by fossil fuel combustion (IPCC, 2007e, p 2-3). The remaining 20 percent originates from anthropogenic land use changes. The main fossil fuel combustion CO_2 emission source categories include electric power generation (35 percent of total anthropogenic CO_2 emissions [International Energy Agency, 2005), transportation (20 percent), other industry (20 percent), and residential (20 percent). Global emissions in all of these fossil fuel categories are currently increasing, and are expected to do so for at least several decades; however, as discussed in the following text, longer term future trends in global CO_2 emissions are uncertain.

Increased CO_2 emissions are associated with commercial, industrial, and population growth; therefore, CO_2 emissions from developing nations such as China and India are increasing rapidly. For example, China is currently constructing the equivalent of two 500-megawatt (MW) coal-fired power plants per week (Katzer et al., 2005). In the developed world, growth in population and industry, along with an aging fleet of existing power plants, dictate the need to construct new electric generating capacity. In the United States, more than 70 coal-fired power plant projects are currently proposed at various stages of development (EPA, 2007b).

Overall, the electric power industry was the single largest contributor to greenhouse gas emissions in 2005, responsible for approximately 33 percent of all greenhouse gas emissions from the U.S. in 2005 (EPA, 2007a). The second and third highest contributors were transportation and industry, emitting 28 percent and 19 percent respectively.

Concentrations of CO_2 in the atmosphere has been the main focus of scientific investigation with regard to anthropogenic effects on Earth's climate, largely because CO_2 is the second highest concentration of greenhouse gas in the atmosphere behind water vapor. However, other atmospheric components lend themselves to anthropogenic forcing including methane, nitrous oxide, and halocarbons. In addition, aerosols are now believed to also play a key role.

3.1 Carbon Dioxide

Testing of the air in bubbles trapped in ice cores has revealed that atmospheric CO_2 levels are 35 percent higher than before the Industrial Revolution (BRAC ND, EPA, 2007a). The atmospheric concentration of CO_2 in 2005 exceeded the natural range over the last 650,000 years (Le Treut et al., 2007). From 1990 to 2005 the U.S. CO_2 emissions increased by 20.3 percent (EPA, 2007a).

Approximately 84 percent of the 2005 greenhouse gas emissions from the United States were CO_2 (EPA, 2007a). The main anthropogenic source of CO_2 in the atmosphere is the consumption of energy from fossil fuels (IPCC, 2001). Other factors include burning of solid waste, trees and wood products, and also as a result of other chemical reactions including production of cement. CO_2 from fossil fuel combustion accounted for 79 percent of CO_2 emissions in 2005. Electricity generators consumed 36 percent of the U.S. energy from fossil fuels and emitted 41 percent of the CO_2 from fossil fuel combustion in 2005. Of the fossil fuel CO_2 emissions in the United States in 2005, approximately 40 percent was from petroleum, 40 percent was from coal, and 20 percent was from natural gas. Approximately 80 percent of electricity generation was produced using coal (EPA, 2007a).

A carbon sink is defined as a place where carbon accumulates and is stored, such as in plants as they accumulate CO_2 during the process of photosynthesis and store it in their tissues as carbohydrates and other organic compounds (Australian Greenhouse Office, 2007). Changes to or reductions in plant cover result in a reduction in the ability of biological processes to remove CO_2 from the atmosphere. This contributes to increasing CO_2 levels in the atmosphere. Thus changes in land use are the other major contributor to CO_2 concentrations in the atmosphere, primarily through deforestation, the effects of fire and grazing on savannahs and grasslands; reductions in peats and wetlands; and conversion of natural vegetation to agriculture (IPCC, 2001a).

3.2 Methane

The global atmospheric concentration of methane is over 140 percent higher than pre-industrial levels. The atmospheric concentration of methane in 2005 exceeded the natural range over the last 650,000 years (Le Treut et al., 2007). Proportionally, methane makes up a much smaller part of greenhouse gases in the atmosphere than CO_2. However, methane is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC, 2001a; Hofmann, 2004 in EPA, 2007a).

The primary anthropogenic source of methane in the United States in 2005 was landfills. Other anthropogenic sources of methane in the atmosphere include utilization of fossil fuel which includes fugitive emissions plus uncombusted fractions, ruminants (cattle), waste treatment, rice agriculture, biomass burning (IPC, 2001b), and coal mining (EPA, 2007a). In 2005, methane represented 7.5 percent of all U.S. emissions. Methane emissions resulting from generation of electricity from coal-fired power plants represent approximately 0.2 percent of total methane emissions from energy production (EPA, 2007a).

3.3 Nitrous Oxide

Atmospheric concentrations of nitrous oxide are 18 percent higher than pre-industrial levels (Le Treut et al., 2007). While total nitrous oxide emissions are lower than CO_2 emissions, nitrous oxide is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere.

The primary anthropogenic source of nitrous oxide in the atmosphere is agricultural soils. Nitrous oxide is a primary ingredient in many common fertilizers used in agricultural operations. Other anthropogenic sources include cattle and feedlots, industrial sources (this

would include the energy industry), and biomass burning (IPCC, 2001a). Emissions resulting from coal-fired power plants represented 65 percent of all nitrous oxide emissions from stationary sources, and 17 percent of all nitrous oxide emissions from energy production (EPA, 2007a).

3.4 Halocarbons

Halocarbons are any of various compounds of carbon and one or more halogens (such as chlorine or fluorine). Chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs) and halons (halocarbons containing bromine) are ozone depleting substances covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. Since implementation of the Montreal Protocol, production of ozone depleting substances is being phased out, and these substances are being replaced by hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6), as they do not deplete stratospheric ozone. They are, however, powerful greenhouse gases with high global warming potentials and extremely long atmospheric lifetimes. Emissions resulting from the substitution of ozone depleting substances have been increasing, and are both the largest and fastest growing source of HFC, PFC, and SF_6 emissions (EPA, 2007a).

4. Projections of Future Changes in Climate

4.1 Establishment of the Intergovernmental Panel on Climate Change

Concerns about human impacts on world climate led to efforts to organize and mobilize the scientific community world-wide. The first World Climate Conference organized by the World Meteorological Organization in 1979 called for, "global cooperation to explore the possible future course of global climate and to take this new understanding into account in planning for the future development of human society" (IPCC, 2004).

The Advisory Group on Greenhouse Gases was established by the United Nations Environment Programme (UNEP), World Meteorological Organization (WMO), and International Council for Science as a result of a joint 1985 conference to assess the role of CO_2 and of other greenhouse gases in climate variations and associated impacts. The Advisory Group on Greenhouse Gases was established, "… to ensure periodic assessments of the state of scientific knowledge on climate change and its implications" (IPCC, 2004).

The Intergovernmental Panel on Climate Change (IPCC) by the UNEP was established in concert with the WMO in 1988. The role of the panel is to, "assess on a comprehensive, objective, open and transparent basis the best available scientific technical and socio-economic information on climate change from around the world. The assessments are based on information contained in peer-reviewed literature and, where appropriate documented, in industry literature and traditional practices" (IPCC, 2007a).

4.2 Predicting Climate Change

The IPCC's predictions for future climate change are based primarily on general circulation model (GCM) results. GCMs account for a variety of parameters and interactions within the earth's atmosphere, oceans, and land cover to predict the resulting climate impacts resulting from a given set of input conditions.

GCMs evaluate climate by dividing the earth's atmosphere into discrete grid boxes and numerically solving the fundamental equations describing the conservation of mass, energy, momentum, etc. for each atmospheric grid box, while taking into account the transfer of those quantities between grid boxes. GCMs also consider, often in parameterized form, the physical processes within the boxes, including sources and sinks of these quantities (NASA, 2007a).

Because of the large size of the GCM grid boxes (typically between 250 and 600 kilometers in horizontal resolution), GCM resolution is not typically sufficient to account for small-scale phenomena. Some physical processes, such as those related to clouds, occur at smaller scales and cannot be properly modeled. Instead, their known properties must be averaged over the larger scale in a technique known as parameterization. This is one source of uncertainty in GCM-based simulations of future climate. Other sources of uncertainty relate

to the simulation of various feedback mechanisms. The term "feedback" refers to mechanisms by which a change in one climate parameter can influence other climate parameters. Examples of paired feedback mechanisms include water vapor and warming, clouds and radiation, and ocean circulation and ice and snow albedo. As a result of these uncertainties, different GCMs may simulate different responses to the same forcing because of the ways certain processes and feedbacks are modeled (IPCC, 2007c).

Even considering the uncertainties mentioned in the previous text, GCMs have advanced to a point where model outputs generally reproduce observed features of recent climate and past climate changes (IPCC, 2007d, p. 591).

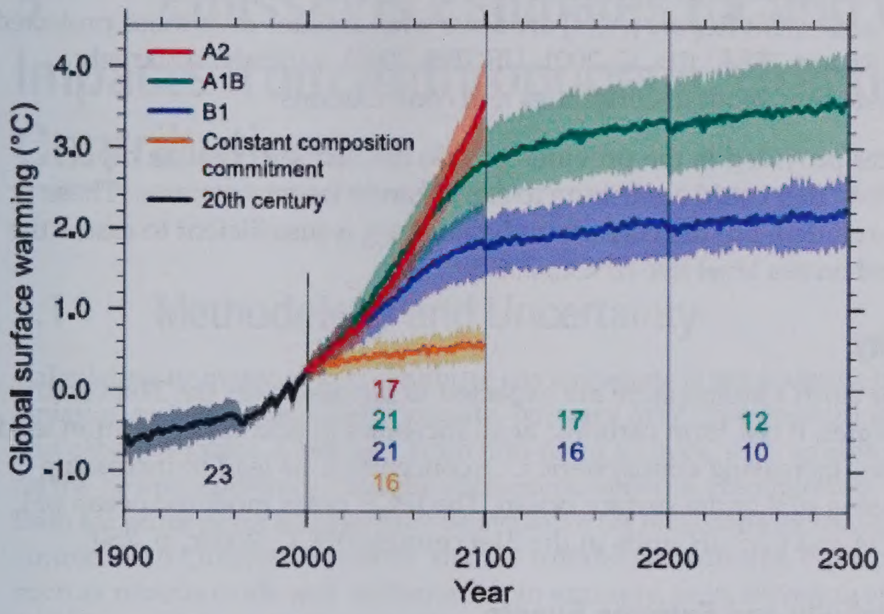
4.3 Summary of IPCC-Reported Predictions for the Effects of Future Climate Change

The IPCC's Working Group I has published its contribution to the IPCC's Fourth Assessment Report (AR4), "The Physical Science Basis." Chapter 10 ("Global Climate Projections") provides predicted climate change impacts for a variety of modeled scenarios. For the 21st century, the IPCC predicts changes to several climate parameters, including temperature, precipitation, ocean acidity, and sea level. The IPCC's predictions for future climate change are summarized in the following subsections. Note that the following climate change impact discussions are not intended to address every conceivable environmental impact of climate change. Rather, the following climate change predictions are presented to summarize the primary climate change impacts noted by the IPCC in the AR4.

4.3.1 Surface Air Temperature

Based on model simulations applied to six different greenhouse gas emission scenarios, the IPCC projected an increase of the globally averaged surface temperature of 1.8 to 4.0°C for the end of the 21st century relative to 1980 to 1999 period. The model projections of temperature changes are illustrated graphically in Figure 5. The various lines represent separate IPCC emission scenarios. A2 represents the rapid population growth scenario; A1B represents the balanced energy scenario; and B1 represents the low emissions intensity scenario.

FIGURE 5
Summary of Predicted Temperatures



Source: IPCC, 2007d, Figure 10.4

4.3.2 Precipitation

Globally, higher temperatures should lead to higher rainfall because a warmer climate will contribute to higher rates of evaporation and a more active hydrologic cycle. However, the spatial distribution of moisture and precipitation changes is complex and drives regionally distinct trends. On a global scale, a poleward shift in storm tracks is projected to continue that trend observed in the last half century (IPCC, 2007; Yin, 2005). As a result, increases in the amount of precipitation are very likely at high latitudes, while decreases are likely in most subtropical land regions (IPCC, 2007). The prediction of changes in precipitation patterns continues to carry great uncertainty, and there remains a lack of consensus for many regions. However, recent scientific opinion appears to support the broad notion that "wet regions get wetter and dry regions get drier" (Held and Soden, 2006; North, personal communication).

Additionally, the intensity of precipitation events is projected to increase, particularly in tropical and high latitude areas that experience increases in mean precipitation. In areas where mean precipitation is predicted to decrease, precipitation intensity is projected to increase, with longer periods between rainfall events. A tendency is predicted for drying of the mid-continental areas during summer, indicating a greater risk of droughts in those regions (IPCC, 2007d, p. 750).

4.3.3 Sea Level

Mean sea level is expected to rise over the 21st century by 0.18 to 0.59 meter, reflecting the range of modeled scenarios. Thermal expansion (warmer water occupies more space) is the largest component of the projected sea level rise, contributing from 70 to 75 percent of the increase. Melting glaciers, ice caps, and the Greenland Ice Sheet are also projected to contribute positively to sea level. Models indicate that the Antarctic Ice Sheet will receive

increased snowfall without experiencing substantial surface melting, thus gaining mass and thus tending to reduce mean sea level (IPCC, 2007c, p. 750-751). The increases in sea level projected in the Fourth Assessment Report (AR4) are somewhat smaller than those projected in the Third Assessment Report (TAR) (IPCC, 2001; USGRP, 2001), a difference largely related to improved information about uncertainties and contributions.

The sea level rise estimates provided in the previous text do not include possible rapid dynamic changes in ice flow that could contribute to significantly larger increases. These larger values cannot be excluded, but the current understanding is insufficient to assess the likelihood or upper bound on sea level rise (IPCC, 2007).

4.3.4 Ocean Acidity

CO_2 concentrations in the earth's atmosphere are expected to increase over the 21st century. When CO_2 dissolves in water, it can form carbonic acid. Increases in acid concentration tend to result in lower pH; thus, increasing atmospheric CO_2 concentrations lead to increasing acidification (and decreasing pH) of the surface ocean. The IPCC notes modeled ocean pH reductions of between 0.14 and 0.35 pH units in the 21st century (IPCC, 2007c, p. 750).

4.3.5 Climate Variability and Extreme Events

Increased variability in future climate and extreme events are predicted as a result of future climate change. The IPCC reports that temperature extremes, heat waves, and heavy precipitation events are "very likely" to become more frequent, and that future tropical cyclones are "likely" to become more intense (IPCC, 2007e). In its assessment of North America regional climate projections (Christensen et al., 2007), the IPCC reports similar findings of increased prolonged hot spells and increased diurnal temperature range, particularly in summer.

4.3.6 Climate Tipping Points

Some climatologists have postulated the existence of climate "tipping points." A tipping point would occur if an aspect of the climate system were to reach a state such that strong amplifying feedbacks were activated by only moderate additional warming. For example, some scientists have speculated that only moderate additional warming beyond current conditions might induce disintegration of the West Antarctic ice sheet and Arctic sea ice. Amplifying feedbacks could include increased absorption of sunlight as melting exposes darker surfaces and increasing iceberg discharge as the warming ocean melts ice shelves that would otherwise inhibit ice flow (NASA, 2007c). If such accelerated melting were to occur, a range of potential environmental impacts could result, including sea level rise, changes in ocean currents, and impacts to species.

5. Emissions Estimates for and Climate Impacts from Anthropogenic Greenhouse Gas Contributions

5.1 Methodology and Uncertainty

Calculating or measuring greenhouse gas emissions is not a simple task. Smoke stack emission tests are reasonably accurate, but vary over time depending on climate, production and other variables. Emissions from non-point sources, such as motor vehicles, vary based on the octane, additives, catalytic converters, operating temperature and other variables. Data for older point sources may be available for emissions included under National Ambient Air Quality Standards, such as sulfates and nitrates, but not for greenhouse gases, such as nitrous oxide and methane. As an example, in its *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (EPA, 2007a), EPA estimates the range of uncertainty in its 2005 data for GHG emissions from "fossil fuel combustion" to be only minus 2 percent to 5 percent for CO_2, but minus 30 percent to 112 percent for methane emissions from stationary combustion and minus 22 percent to 189 percent for nitrous oxide emissions from stationary combustion. Ambient air samples can be affected by uneven mixing, upwind sources, deposition, and other variables.

One of the most widely used methods for estimating emissions is the use of emission factors. Used by EPA, DOE, the IPCC and others, emission factors are based on test data of emissions meeting certain testing quality standards. For example, measured CO_2 emissions from Powder River Basin sub-bituminous coal burned in supercritical steam generating facilities are unitized and averaged, yielding an emission factor that characterizes CO_2 emissions per BTU of heat generated through the combustion process, or each ton of coal burned, or some other unit. This emission factor is then used to predict CO_2 emissions from a proposed generating unit, such as the proposed action, based on the design fuel, generating capacity, and pollution or other control methods that will be used to reduce emissions.

5.2 Quantitative Emissions Analysis

5.2.1 Global

Data available for global emissions of GHGs is based less on measurements, in some countries, and more on estimates. In addition, the most comprehensive data is for CO_2 from the "consumption and flaring of fossil fuels," and does not include CH_4, N_2O, or other gases. Table 1 shows estimated CO_2. emissions for 1995 and 2005 by IPCC region, and percent of the total.

TABLE 1
World CO_2 Emissions from the Consumption and Flaring of Fossil Fuels by IPCC Region (million metric tons of CO_2 (MMT CO_2))

IPCC Region	CO_2 1995 (MMT CO_2)	CO_2 2005 (MMT CO_2)	2005 Percent of Total
North America	6,115.03	6,987.78	24.8
Central & South America	849.88	1,096.16	3.9
Europe	4,272.41	4,674.75	16.6
Eurasia	2,480.82	2,577.82	9.1
Middle East	894.41	1,450.81	5.1
Africa	817.88	1,042.92	3.7
Asia & Oceania	6,559.45	10,362.49	36.8
World Total	**21,989.88**	**28,192.74**	

Source: EIA, 2007d

Table 2 shows direct GHG emissions from generation of electricity by fuel source for 1995 and 2005. The fourth column shows how much electricity was generated using each of the listed fuel sources for 2005. Because the emissions and power data are from different sources, not all of the categories match up. Nevertheless, the data show that, among the major fuel sources, coal produced the largest quantity of CO_2 per megawatt hour, followed by petroleum, natural gas, and geothermal. Nuclear, hydroelectric and wind generation have no GHG emissions, although all sources have associated life cycle impacts.

TABLE 2
GHG Emissions Related to Generation of Electricity (MMT CO_2 Eq.) and Electricity Generation by Fuel Source for 2005 (1,000 megaWatt-hours (MWhr))

Gas/Fuel Type or Source	GHG 1995[1] (MMT CO_2 Eq.)	GHG 2005[1] (MMT CO_2 Eq.)	Power 2005[2] (1,000 MWhr)
CO_2	**1,958.7**	**2,405.8**	**2,513,609**
Fossil Fuel Combustion	1,939.3	2,381.2	
Coal	*1,648.7*	*1,958.4*	2,013,179
Natural Gas	*229.5*	*320.1*	757,974
Petroleum	*60.7*	*102.3*	122,522
Geothermal	*0.3*	*0.4*	
other gases			16,317
Nuclear			781,986
Hydroelectric Conventional			270,321
Other Renewables			87,213
Pumped Storage			-6,558
Other			12,468
Net Generation All Sources			4,055,423
Municipal Solid Waste Combustion	15.7	20.9	

TABLE 2
GHG Emissions Related to Generation of Electricity (MMT CO_2 Eq.) and Electricity Generation by Fuel Source for 2005 (1,000 megaWatt-hours (MWhr))

Gas/Fuel Type or Source	GHG 1995[1] (MMT CO_2 Eq.)	GHG 2005[1] (MMT CO_2 Eq.)	Power 2005[2] (1,000 MWhr)
Limestone & Dolomite Use	3.7	3.7	
CH_4	**0.6**	**0.7**	
Stationary Combustion*	0.6	0.7	
N_2O	**8.5**	**10.0**	
Stationary Combustion*	8.0	9.6	
Municipal Solid Waste Combustion	0.5	0.4	
SF_6	**21.8**	**13.2**	
Electrical Transmission and Distribution	21.8	13.2	
Total Emissions	**1,989.5**	**2,429.8**	

*Includes only stationary combustion emissions related to the generation of electricity
Sources:[1] EPA, 2007a; [2] EIA, 2007c

5.2.2 Global CO_2 Emissions from Fossil Fuels Including Coal Fired Power Plants

The IPCC states that emissions from the burning of fossil fuels is an important component of global anthropogenic GHG emissions. Table 3 summarizes CO_2 emissions from global sources of fossil fuels, including coal fired power plants.

TABLE 3
Contribution of CO_2 Emissions from Coal-Fired Power Plants

CO_2 Emission Sources	CO_2 Emissions (million tons/yr)	Source of Data
Global total from land and ocean	855,592	IPCC AR4 Figure 7.3, p. 515, 2007
Existing global total from fossil fuels	29,085	IPCC Summary for policymakers, p. 2, 2007
Existing global total from coal-fired power plants	7,722	Stern Review on the Economics of Climate Change, Annex 7.b

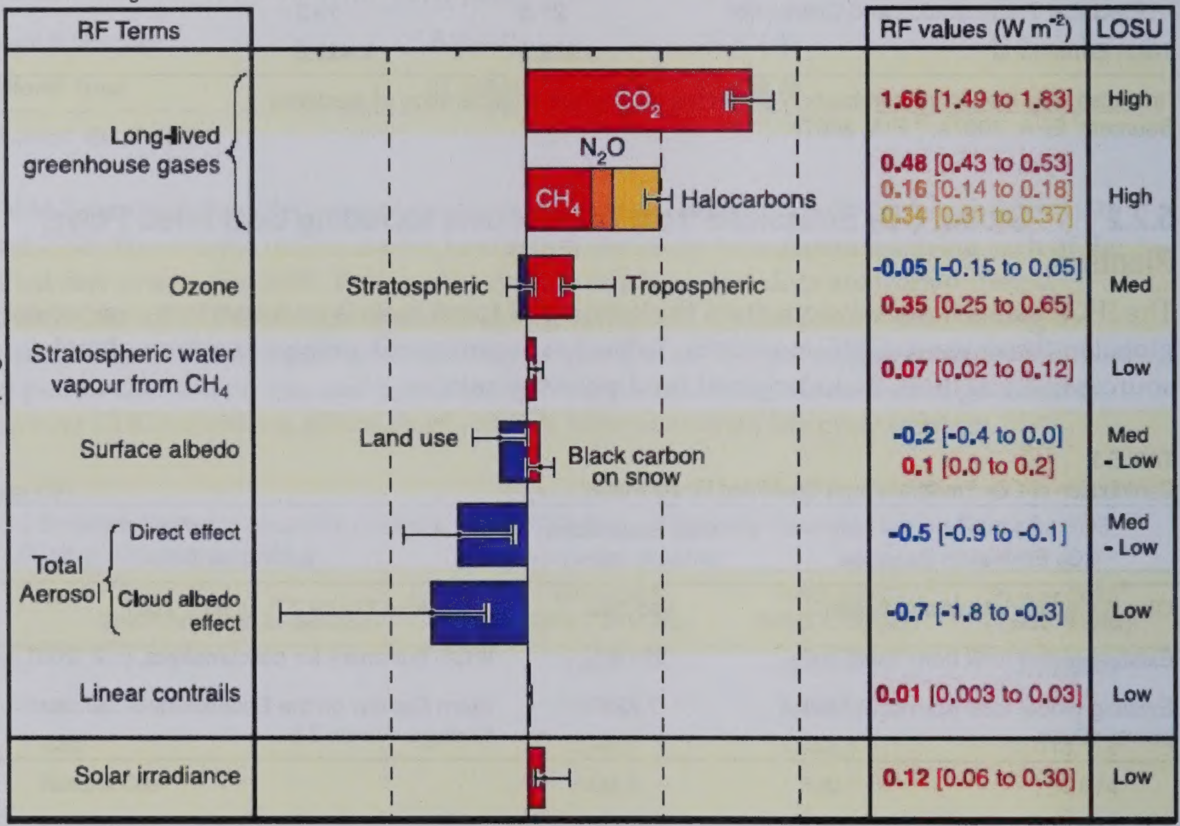
According to the IPCC, the range of uncertainty in the global CO_2 emissions from fossil fuel combustion and cement production is ±1,212 million tons per year of CO_2 (IPCC, 2007d, p. 516). Thus, the CO_2 emissions increases from a single plant (for example, 12 million tons per year), or even the emissions increases resulting from several new plants considered together, are well within the range of uncertainty in the IPCC's estimates.

5.3 Climate Impacts from Anthropologic Greenhouse Gas Emissions

5.3.1 Global

The IPCC states that, "[m]ost of the observed increase in global average temperatures since the mid-20th century is very likely because of the observed increase in anthropogenic greenhouse gas concentrations" (IPCC, 2007d, p 2-3). Further, the IPCC concludes that "[i]t is likely that there has been significant anthropogenic warming over the past 50 years averaged over each continent except Antarctica" (IPCC, 2007d, p 2-3).

FIGURE 6
Radiative Forcing on Climate Between 1750 and 2005



Source: IPCC, 2007d, Figure SPM.2

As reflected in Figure 6, the combined radiative forcing resulting from all known factors since 1750 is 1.84 Watts per square meter (W/m^2). Anthropogenic CO_2 emissions are the largest component of this estimated forcing, estimated at 1.66 W/m^2. It should be noted that the level of scientific understanding (LOSU) for the various forcings in Figure 6 ranges from low to high. There is a high LOSU for the greenhouse gas forcings because these forcings are well established based on theoretical and laboratory study. The LOSU for some other significant forcings (for example, cloud albedo effect) is currently low; thus, the magnitudes of several of the forcings would be expected to change in future IPCC assessment reports as the state of the science progresses. The margins of uncertainty in Figure 6 should be noted as

well. In many cases, the range of uncertainty is wide, again reflecting the potential for more refined estimates in future IPCC assessment reports.

To summarize, quantification and estimation of greenhouse gas emissions and their effect is influenced by uncertainty encountered and compounded at multiple levels, from measurement of emissions to predicting the long-term effects of future emissions.

5.3.2 Single source

Individual sources of CO_2 (for example, a factory, power plant or other industrial process that emits CO_2) have an extremely small contribution to the global collection of CO_2 emissions (both natural and anthropogenic). Emissions from individual sources fall well within the margins of uncertainty associated with general circulation model (GCM) predictions of climate parameters. It is not possible to predict the potential climate impacts that might result from an individual CO_2 emission source. Thus, GCM predictions of future changes in climate would not be affected by the presence or absence of any individual source of CO_2 emissions.

The concept that climate impacts cannot be attributed to an individual CO_2 emissions source is reinforced by a Special Rule published by the U.S. Fish & Wildlife Service in connection with listing the polar bear as a threatened species under the Endangered Species Act (ESA):

> There is currently no way to determine how the emissions from a specific project under consultation both influence climate change and then subsequently affect specific listed species or critical habitat, including polar bears. As we now understand them, the best scientific data currently available does not draw a causal connection between GHG emissions resulting from a specific Federal action and effects on listed species or critical habitat by climate change, nor are there sufficient data to establish the required causal connection to the level of reasonable certainty between an action's resulting emissions and effect on species or critical habitat. (Special Rule, 50 CFR Part 17, Endangered and Threatened Wildlife and Plants; Special Rule for the Polar Bear (Ursus maritimus) Throughout Its Range, 73 Fed. Reg. 28306, 28313 (May 15, 2008))

6. Potential Impacts of Greenhouse Gas Emission Sources

6.1 Direct Impacts

Emitting CO_2 into the atmosphere is not itself an adverse environmental impact. It is the increased concentration of CO_2 in the atmosphere, potentially resulting in global climate change and the associated consequences of climate change, that may result in environmental effects (for example, sea level rise, loss of snowpack, severe weather events). Although it is possible to generally estimate a project's incremental contribution of CO_2 into the atmosphere, it is not possible to determine whether or how an individual project's relatively small incremental emissions contribution might translate into physical effects on the environment. Given the complex interactions between various global and regional-scale physical, chemical, atmospheric, terrestrial, and aquatic systems that may result in the physical expressions of global climate change, it is not possible to discern whether the presence or absence of CO_2 emitted by a given project would result in any altered conditions. See Section 5.2.2 of the previous text for additional details.

6.2 Cumulative Impacts

Greenhouse gas emissions are appropriately considered a cumulative impacts issue, and the construction and operation of any new CO_2 source, including the proposed Station, would comprise an incremental increase (albeit relatively small) to cumulative GHG emissions, unless the increase were offset by reductions from other sources, such as the retirement of older, less efficient plants. Absent policy changes or changes in market forces, if there is a continuing trend over the next several decades of an increased number of fossil fuel-fired power plants in the U.S. and around the globe, these plants would continue to be a relatively major contributor to the cumulative anthropogenic emissions pool, absent offsets, capture and sequestration, etc. This anthropogenic CO_2 emissions pool would contribute to the total global emissions pool (which also includes natural sources), potentially resulting in a net positive radiative forcing on climate, which could contribute to the current observed and predicted climate change impacts discussed in the previous text.

6.2.1 Social Cost of CO_2 Emissions

Various economists have endeavored to quantify the economic costs to society resulting from climate change. These economic estimates assume that climate change impacts are caused by anthropogenic emissions of greenhouse gases (specified as CO_2). The "social cost of carbon" (SCC), also referred to as the "marginal damage cost," serves as a cost metric for the climate-related cost of CO_2 emissions and is estimated as the net present value of future climate impacts assumed to result from the emission of one ton of CO_2 today.

In its Second Assessment Report (IPCC, 1995), the IPCC reported a wide range of published SCC values, from $1 to $31 per ton of CO_2. Additional studies have been published subsequently, but this cost range remains representative of the SCC values typically reported in the literature. For example, based on an evaluation of 28 published studies, economist and IPCC author Richard Tol concluded that the marginal damage costs of CO_2 emissions are not likely to exceed $12 per ton of CO_2 ($50 per metric ton of carbon) and would likely be substantially smaller (Tol, 2005). This report identified that for some economic scenarios, the estimated SCC is a negative value (meaning that emitting CO_2 represents a benefit to society) and in other cases that the SCC may exceed the range identified in the Second Assessment Report.

The Stern Review on the Economics of Climate Change was published in October 2006 (Stern, 2006). In this report, economist Nicholas Stern suggests that the SCC is on the order of $77 per ton of CO_2 ($85 per metric ton of CO_2, or $311 per metric ton of carbon) for a scenario with no future CO_2 emissions limitations. This value is significantly higher than the typical range of values in the SCC literature as discussed in previous text. For additional discussion of the Stern Review and its methodologies, refer to Tol (2006) and Nordhaus (2007).

More recently, William Nordhaus, Sterling Professor of Economics at Yale University, reported that for a scenario with no future CO_2 emissions limitations (the highest cost scenario), the SCC value is estimated at $7 per ton of CO_2 ($30 per metric ton of carbon) (Nordhaus, 2007).

The wide range of SCC values estimated by the various sources indicates a degree of uncertainty behind these economic estimates; however, the $12 per ton of CO_2 ($50 per metric ton of carbon) SCC estimate provided by Tol (2005) takes into account 28 published studies and is considered a conservative value representative of the body of peer-reviewed SCC literature (Tol states that the cost would likely be less).

6.2.2 Effect on Climate Tipping Points

Although the threshold conditions that would be required to trigger a tipping point in the climate system are not known, some climatologists are concerned that increasing atmospheric concentrations of CO_2 in the future could move the climate system toward a tipping point. Therefore, the collection of current and future anthropogenic activities that contribute to the global pool of CO_2 emissions (including coal-fired power plants) could move the climate system toward a tipping point if the postulated tipping points exist. However, given the current level of understanding of the climate system and uncertainties surrounding the rate of growth in global CO_2 emissions (refer to "Trends in Anthropogenic CO_2 Emissions" in the previous text), it is not possible to determine whether the addition of a single emissions source (or even a group of emissions sources considered together) would cause or contribute to a climate tipping point being triggered.

7. Potential Environmental Impacts of Climate Change

Changes in climate affect ecosystems on a local and regional scale. The IPCC's Working Group II has published its contribution to the IPCC's Fourth Assessment Report (AR4), "Impacts, Adaptation and Vulnerability." This IPCC report indicates that climate change is currently impacting natural resources and is predicted to cause additional impacts in the future. The following subsections provide a brief summary of the climate change impacts on resources discussed by the IPCC.

The following text summarizes the current observed effects of climate change, as well as the predicted future effects of climate change based on information from the IPCC.

7.1.1 Current Observed Impacts of CC/GW on Resources

Wide-ranging observations suggest that natural systems are being affected by regional climate changes. Examples of such regional climate change effects include the following (IPCC, 2007d, p. 1-2):

- Enlargement and increased numbers of glacial lakes resulting from temperature increases
- Increasing ground instability in permafrost regions
- Earlier timing of spring events, such as leaf unfolding, bird migration and egg laying
- Poleward and upward shifts in ranges in plant and animal species
- A trend towards earlier "greening" of vegetation in the spring linked to longer thermal growing seasons
- Shifts in ranges and changes in algal, plankton and fish abundance in high-latitude oceans
- Increases in algal and zooplankton abundance in high-latitude and high-altitude lakes
- Range changes and earlier migrations of fish in rivers
- Effects to biological systems, such as earlier timing of spring events (for example, leaf-unfolding, bird migration, and egg-laying) and poleward and upward shifts in ranges in plant and animal species (IPCC, 2007e).

7.1.2 Projected Future Impacts on Resources

Additional climate-related impacts on natural resources are predicted for the future. The impacts primarily reflect projected changes in precipitation, temperature, sea level, and concentrations of atmospheric CO_2. The magnitude and timing of impacts will vary with the

amount and timing of climate change and, in some cases, the capacity to adapt. Examples of such predicted impacts include the following (IPCC, 2007d, p. 2-8):

- By mid-century, annual average river runoff and water availability are projected to increase by 10 to 40 percent at high latitudes and in some wet tropical areas, and decrease by 10 to 30 percent over some dry regions at middle latitudes and in the dry tropics.
- Drought-affected areas will likely increase in extent. Heavy precipitation events, which are very likely to increase in frequency, will augment flood risk.
- In the course of the century, water supplies stored in glaciers and snow cover are projected to decline, reducing water availability in regions supplied by melt water from major mountain ranges.
- Crop productivity is projected to increase slightly at middle to high latitudes for local mean temperature increases of up to 1 to 3°C depending on the crop, and then decrease beyond that in some regions.
- At lower latitudes, especially seasonally dry and tropical regions, crop productivity is projected to decrease for even small local temperature increases (1 to 2°C).
- Coasts are projected to be exposed to increasing risks, including coastal erosion, because of climate change and sea level rise.
- Coastal wetlands including salt marshes and mangroves are projected to be negatively affected by sea level rise, especially where they are constrained on their landward side, or starved of sediment.
- The balance of positive and negative health impacts will vary from one location to another, and will alter over time as temperatures continue to rise. Critically important will be factors that directly shape the health of populations such as education, health care, public health prevention and infrastructure and economic development.
- Increased risk of extinction to plant and animal species for warming scenarios exceeding 1.5°C, along with major changes in ecosystem structure and function. Negative impacts on marine shell forming organisms (for example, corals) and their dependent species because of progressive acidification of oceans (IPCC, 2007e).

7.1.3 Human Health

According to the IPCC Fourth Assessment Report (Confalonieri et al., 2007), climate change related exposures of importance to human health include:

- Increase in malnutrition and consequent disorders, including those relating to child growth and development
- Increase in number of people suffering from death, disease, and injury from heat waves, floods, storms, fires, and droughts
- Change in the range of some infectious disease vectors

- Contraction or expansion of the geographical range of malaria and change in transmission season
- Increase in burden of diseases resulting in diarrhea
- Increase in cardio-respiratory morbidity and mortality associated with ground-level ozone
- Increase in number of people at risk of dengue
- Some health benefits including fewer deaths from cold, although it is expected that this will be outweighed by negative effects of rising temperatures worldwide, especially in developing countries

8. Global, National and Regional Actions and Possible Mitigation Measures

8.1 Global, National, and Regional Actions

Various national and international conventions, panels, commissions, and scientific or strategically focused entities have been formed to suggest protocols, policies, and goals aimed at reducing greenhouse gas emissions. International treaties and state legislation has been enacted to deal with global climate change. The Kyoto Protocol, an international treaty designed by the United Nations Framework Convention on Climate Change (UNFCC) to secure a global commitment to the reduction of greenhouse gases is perhaps the most well-known initiative. More than 160 countries have signed the treaty to demonstrate their commitment to reduce emissions of greenhouse gases or to engage in emissions trading.

The United States was not a signatory to the treaty and has approached the reduction of greenhouse gas emissions at the federal level on a voluntary basis thus far. However, the U.S. has established a goal of reducing greenhouse gas intensity in the American economy by 18 percent during the period of 2000 to 2012(EPA, 2007). In addition, there have been many actions taken by individual cities, counties, and states to set greenhouse gas policies, plans, and goals. Many states have set greenhouse gas emission targets and established greenhouse gas emission reduction action plans.

With the Kyoto Protocol set to expire after 2012, the United Nations Framework Convention on Climate Change (UNFCCC) convened the United Nations Climate Change Conference (the Conference) in Bali, Indonesia, on December 3, 2007. The Conference included representatives from more than 180 countries (including the United States) and ultimately resulted in a decision to adopt the Bali Action Plan, which sets forth a new negotiating process to be concluded by 2009 that will lead to a post-2012 international agreement on climate change (UNFCCC, 2007).

Currently in the United States, there is no federal requirement that greenhouse gases be regulated through New Source Review (NSR) permitting for individual stationary sources. No federal guidance has as been provided, and no emissions thresholds of concern have been established. However, in the recent *Massachusetts v. EPA* decision, the United States Supreme Court determined that CO_2 meets the definition of an "air pollutant" under the Clean Air Act and that "EPA has the statutory authority to regulate the emission of such gases from new motor vehicles." (U.S. Supreme Court, 2007, p. 30) Although the Court did not conclude that CO_2 was subject to regulation under the Clean Air Act, it directed EPA to make a finding as to whether such regulation is warranted. The Court held that, on remand, EPA must make a determination as to whether greenhouse gas emissions "cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare ...." (U.S. Supreme Court, 2007, pp. 30-32, Clean Air Act §202(a)(1)). It is only if EPA makes "a finding of endangerment [that] the Clean Air Act requires the agency to regulate emissions of the deleterious pollutant from new motor vehicles." U.S. Supreme

Court, 2007, p. 30) An endangerment finding on CO_2 would require EPA to initiate a rulemaking process for regulating CO_2 emissions from new motor vehicles. After such regulations were final, CO_2 would be considered a regulated pollutant under the Clean Air Act, and EPA would be required to initiate a rulemaking process to address CO_2 emissions from stationary sources under Title I of the Clean Air Act.

Independent of any action by EPA, Congress could pass legislation regulating CO_2 emissions from stationary sources. Several such legislative proposals have been drafted, such as the Lieberman-Warner *Climate Stewardship and Innovation Act of 2005(S.2191)*, the Waxman *Safe Climate Act of 2007*, or the Kerry-Snowe *Global Warming Reduction Act*. Climate legislation ultimately passed by Congress may take the form of a "cap-and-trade" program that would establish a national cap on greenhouse gas emissions, a carbon tax that would apply to sources of energy that emit CO_2, or other similar measures.

Regionally in the United States, individual states or groups of states have enacted policies or legislation to reduce CO_2 emissions. For example, the California Public Utilities Commission has adopted an interim Greenhouse Gas (GHG) Emissions Performance Standard that requires all new long-term commitments for baseload generation to serve California consumers be with power plants that have emissions no greater than a combined cycle gas turbine plant (California Public Utilities Commission, 2007). As an additional example, ten northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) have cooperated to create the Regional Greenhouse Gas Initiative (RGGI), a mandatory cap-and-trade program intended to reduce greenhouse gas emissions from the region. Nevada has not enacted any legislation to regulate or reduce carbon emissions.

8.2 Mitigation Measures

The concept of mitigation measures to address global warming has evolved since they were first discussed in the IPCC's First Assessment Report (FAR). The FAR dealt with available cost-effective response measures in terms of mitigation, mainly in the form of carbon taxes without much concern for equity issues. For the IPCC's Second Assessment Report (SAR), the socio-institutional context was emphasized as well as the issues of equity, development and sustainability. In the IPCC's Third Assessment Report (TAR), the concept of mitigative capacity was introduced, and the focus of attention was shifted to sustainability concerns (Rogner et al., 2007).

Most scenarios project that the supply of primary energy will continue to be dominated by fossil fuels until at least the middle of the century (IPCC, 2005a). Within the energy sector, reductions in CO_2 emissions can be accomplished through increased use of nuclear and renewable energy sources, through increased efficiency of existing sources, and through implementation of new technology to existing sources (carbon capture, etc.).

CO_2 capture and storage (CCS) is a process consisting of the separation of CO_2 from industrial and energy-related sources, transport to a storage location and long-term isolation from the atmosphere (IPCC, 2005a). A detailed discussion of CCS is provided in Appendix E of this FEIS.

Although not yet feasible on a large scale for power plants, capture of CO_2 may someday be applied to large carbon point sources including coal-, gas- or biomass-fired electric power-generation or cogeneration facilities, major energy-using industries, synthetic fuel plants, natural gas fields and chemical facilities for producing hydrogen, ammonia, cement and coke. Potential storage methods include injection into underground geological formations, in the deep ocean or industrial fixation as inorganic carbonates. Application of CCS for biomass sources could result in the net removal of CO_2 from the atmosphere. Storage capacity in oil and gas fields, saline formations and coal beds is considered to be large but currently uncertain. Clarification of the nature and scope of long-term environmental consequences of ocean storage requires further research. Concerns around geological storage include rapid release of CO_2 as a consequence of seismic activity, the impact of old and poorly sealed well bores, and impacts to ground water resources. Overall capacity estimates for CCS are still under debate. In absence of explicit government policies requiring CCS, it is unlikely to be deployed on a large scale by 2030. (Sims et al., 2007). CCS in underground geological formations is a new technology with potential to make an important contribution to mitigation by 2030. Technical, economic and regulatory developments will affect the actual contribution (IPCC, 2007d).

Despite anticipated reductions in emissions from expanded use of nuclear and renewable energy sources, increased efficiency, and increased use of sustainable design, the global energy supply will continue to be dominated by fossil fuels for several decades to come. To reduce the resultant GHG emissions will require a transition to zero- and low-carbon technologies, which will require policy intervention on an international scale (Sims et al., 2007).

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Appendix N

Visual Inventory Forms

White Pine Project *Visual Contrast Rating Worksheet: Proposed Action* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Proposed Action**		
KOP	**KOP 1: Cherry Creek**		
VRM Class	**The Proposed Action power plant site is located in an area of VRM Class III. KOP 1 is located in an area of VRM Class II.**		
Distance From KOP	**Approximately 12 miles**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	The cleared site would be visible in the distance from this location as would the evaporation ponds.	The rectangular shape of the partially cleared site and project facilities would contrast with adjacent and nearby vegetated areas.	The concave cylindrical shape of the cooling towers would be clearly seen when looking down into Steptoe Valley from this location. Other large facilities such as the stacks and coal storage areas along with the power plant would also be seen, but would not be as visible as the cooling towers.
Line			The cooling towers and stacks would be visible vertical elements.
Color	Brownish – gray earth colors. Cleared areas would be the color of the graded earth (browns).	Some existing vegetation would be removed and some would be left in place.	The concrete cooling towers would contrast in color with the adjacent landscape. Over time the color of the concrete would darken and the contrast would be less. Other facilities would be painted earth tones to reduce visual impacts. Coal storage areas would be black.
Texture			The texture of facilities would not be noticed much from this distance.
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	3	3	2
Line	4	4	3
Color	3	3	3
Texture	3	4	3

White Pine Project

Visual Contrast Rating Worksheet: Proposed Action

EDAW/CH2M HILL

Does design meet VRM Class management objectives? Yes for VRM Class III.

Explain: The view from this KOP into Steptoe Valley is very expansive. The Proposed Action would be a small part of that view. The cooling towers would be very visible from this location but would not be silhouetted against the sky, which would reduce their visual impact. Cherry Creek is far enough away from the site that most of the rest of the project facilities would not be visually distinct. Contrasts with the existing characteristic landscape would occur, but would generally be "weak" so VRM Class III objectives would be met.

Additional mitigation measures recommended. None.

White Pine Project ***Visual Contrast Rating Worksheet: Proposed Action*** **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Proposed Action**		
KOP	**KOP 2: Pony Express Route & CR 18 (visual simulation prepared for this KOP)**		
VRM Class	**The Proposed Action power plant site is located in an areas of Class III. KOP 2 is located in an area of VRM Class II.**		
Distance From KOP	**Approximately 4.5 miles**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	The cleared site would not be seen from this viewing distance.	Vegetation that would be removed would be too far away to be seen in any detail from this location.	The concave cylindrical shape of the cooling towers and the cylindrical shape of the stacks would be very visible in front of mountains in the background from this location (but would not be silhouetted against the sky). A variety of large-scale block-like and angular forms of various project facilities associated with the power plant would also be visible from this KOP.
Line			Cooling towers and stacks would be visible as vertical elements from this location. Parts of some long horizontal facilities (coal storage areas and storage berms) would also be seen.
Color	Brownish – gray earth colors.	Sage green and grays.	The concrete cooling towers and stacks would be noticed and their color would contrast to some degree with the adjacent landscape and sky. Other smaller facilities that would be painted earth tones to reduce visual impacts would be less visible.
Texture			The smooth concrete of the cooling towers would be noticeable. The texture of other facilities would not be noticed as much from this distance.

White Pine Project
Visual Contrast Rating Worksheet: Proposed Action
EDAW/CH2M HILL

Degree of Contrast 1 = Strong; 2 = Moderate; 3 = Weak; 4 = None	**Land/Water**	**Vegetation**	**Structures**
Form	3	4	2
Line	3	4	2
Color	2	4	2
Texture	3	4	3

Does design meet VRM Class management objectives? Yes for VRM Class III objectives.

Explain: The distance (4.5 miles) between the KOP and the Proposed Action power plant site is great enough that changes to the existing land and vegetation would not be very (or at all) noticeable. Larger facilities such as the cooling towers and stacks, and the top of the power plant would be seen to the south by people driving east or west on this section of County Road 18. The cooling towers and stacks would be silhouetted against the sky, which would increase their visibility. Contrasts with the characteristic landscape would be "low to moderate" and would meet VRM Class III objectives.

Changes to the characteristic landscape as a result of the cleared water pipeline right-of-way would be noticed from this KOP, but only for a short time by people driving past the KOP location and looking to the immediate left or right (and up the cleared right-of-way). The VRM objectives for Classes II and III would be met.

Additional mitigation measures recommended. None.

White Pine Project *Visual Contrast Rating Worksheet: Proposed Action* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Proposed Action**		
KOP	**KOP 3: Lincoln Highway (visual simulation prepared for this KOP)**		
VRM Class	**The Proposed Action power plant site is located in an area of VRM Class III. KOP 3 is also located in an area of VRM Class III.**		
Distance From KOP	**Approximately 2.5 miles**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	Land cleared for site development would not be clearly seen from this KOP.		The three concave cylindrically shaped cooling towers and stacks would be visible from this location, but would not be silhouetted against the sky. In addition, other facilities such as the power block, coal storage areas, substation, and transmission lines would be seen from this KOP.
Line			Horizontal facilities (coal storage areas, storage berms, and transmission lines) and tall vertical facilities (cooling towers and stacks) would be noticeable from this KOP.
Color	Cleared site would be brown and gray.	Existing vegetation would be removed and some ornamental vegetation would be planted at the facility and seen from this KOP.	The concrete cooling towers would contrast with the background terrain. Other facilities would be painted with non-reflective paint to reduce visual impacts. Coal storage areas would be black and would contrast when not covered in snow.
Texture			The texture of facilities would contrast from the nearby landscape when viewed from this distance.

White Pine Project *Visual Contrast Rating Worksheet: Proposed Action* **EDAW/CH2M HILL**			
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	3	3	2
Line	3	3	2
Color	3	3	2
Texture	3	3	3

Does design meet VRM Class management objectives? Yes for VRM Class III.

Explain: This location is far enough away so that although some of the larger facilities would be noticeable, they would lie low on the horizon. Changes to the characteristic landscape would be "low" and as a result, objectives for VRM Class III would be met.

Additional mitigation measures recommended. No.

White Pine Project *Visual Contrast Rating Worksheet: Proposed Action* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Proposed Action**		
KOP	**KOP 4: Highway 93 (at a turn off)**		
VRM Class	**The Proposed Action power plant site is located in an area of VRM Class III. KOP 4 is also located in an area of VRM Class III.**		
Distance From KOP	**Approximately 12 miles**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	Relatively flat land would be cleared, but would require relatively little grading. The site would be rectangular in shape and could be partially seen from this KOP.	Existing vegetation would be retained where possible, but extensive areas would be cleared to accommodate project facilities. Cleared areas would be seen from this KOP.	The tops of the tallest facilities (primarily the cooling towers and the stacks) could be seen and would be partially silhouetted against the sky.
Line			Horizontal facilities (coal storage areas, storage berms, and transmission lines) and tall vertical facilities (cooling towers and stacks) would be noticeable from this KOP
Color			The cooling towers would contrast in color with the adjacent landscape and sky. Other facilities would be painted with non-reflective paints to reduce visual impacts. Coal storage areas would be black and would contrast when not covered in snow.
Texture			Texture of facilities would somewhat contrast with nearby landscape.

White Pine Project *Visual Contrast Rating Worksheet: Proposed Action* **EDAW/CH2M HILL**			
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	4	4	1
Line	4	4	1
Color	4	4	2
Texture	4	4	3
Does design meet VRM Class management objectives? Yes for both VRM Class III. **Explain:** The Proposed Action site and facilities would be noticeable from this KOP. The cooling towers and stacks would be silhouetted against the background mountains from this location. The level of contrast with the landscape seen from this KOP would be "weak to "moderate" (form would be "strong") which would meet VRM Class III objectives. **Additional mitigation measures recommended.** No.			

White Pine Project *Visual Contrast Rating Worksheet: Proposed Action* EDAW/CH2M HILL			
Project Name	**White Pine**		
Alternative	**Proposed Action**		
KOP	**KOP 5: McGill**		
VRM Class	**The Proposed Action power plant site is located in an area of VRM Class III. KOP 5 is also located in an area of VRM Class III.**		
Distance From KOP	**Approximately 21 miles**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form			This KOP is within the seen area of the Proposed Action site. Viewers could see the tops of some of the taller structures such as the cooling towers and the stacks in the distance. The tops of these structures might be silhouetted against the sky or background mountains, but due to the distance, would be barely noticed.
Line			Tops of structures could be seen silhouetted against the sky.
Color			May see a slight contrast in the concrete color of the cooling towers.
Texture			Not seen.
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	4	4	3
Line	4	4	3
Color	4	4	4
Texture	4	4	4
Does design meet VRM Class management objectives? Yes for VRM Class III. **Explain:** Changes to the characteristic landscape from this KOP would be very low, which would meet the objectives of VRM Class III. **Additional mitigation measures recommended.** No.			

White Pine Project *Visual Contrast Rating Worksheet: Proposed Action* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Proposed Action**		
KOP	**KOP 6: Highway 50**		
VRM Class	**VRM Class III**		
Distance From KOP	**Within 1/4 mile**		
Proposed Activity Description: **Transmission Line and Substation**			
	Land/Water	**Vegetation**	**Structures**
Form	Cleared right-of-way would introduce rectilinear forms where seen.		The tower structures would introduce geometric forms to the landscape.
Line	300-foot wide right-of-way cleared of large vegetation would introduce rectilinear forms where seen.	300-foot wide right-of-way cleared of large vegetation will follow the transmission line.	Transmission line conduit would cross over the highway.
Color		Cleared right-of-way would change type and color of exiting vegetation.	
Texture			
Degree of Contrast 1 = Strong; 2 = Moderate; 3 = Weak; 4 = None	**Land/Water**	**Vegetation**	**Structures**
Form	2	2	2
Line	2	2	3
Color	3	3	3
Texture	3	3	3

Does design meet VRM Class management objectives? Yes, the objectives of VRM Class III would be met.

Explain: Only part of the cleared right-of-way would be seen. The most visible elements would be the tower structures. Changes to the characteristic landscape from this KOP would be low to moderate, which would meet or exceed the objectives of VRM Class III. The substation would be screened from view from the highway by a small hill.

Additional mitigation measures recommended. None.

White Pine Project *Visual Contrast Rating Worksheet: Alternative 1* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Alternative 1**		
KOP	**KOP 1: Cherry Creek**		
VRM Class	**VRM Class III**		
Distance From KOP	**Approximately 23 miles**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	Not seen.	Not seen.	Tops of three cooling towers in seen area, may see tops in distance.
Line	Not seen.	Not seen.	Tops of three cooling towers in seen area, may see tops in distance.
Color	Not seen.	Not seen.	Tops of three cooling towers in seen area, may see tops in distance.
Texture	Not seen.	Not seen.	NA
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	NA	NA	4
Line	NA	NA	4
Color	NA	NA	4
Texture	NA	NA	NA

Does design meet VRM Class management objectives? Yes for Class III (not seen).

Explain: Other than the tops of the three cooling towers and stacks (which would be 23 miles away), none of the Alternative 1 site would be seen from KOP 1.

Additional mitigation measures recommended. None.

White Pine Project *Visual Contrast Rating Worksheet: Alternative 1* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Alternative 1**		
KOP	**KOP 2: Pony Express Route (County Road 18)**		
VRM Class	**VRM Class III**		
Distance From KOP	**Approximately 15 miles**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	Not seen.	Not seen.	The tops of three cooling towers and stacks could be visible in distance silhouetted against the sky.
Line	Not seen.	Not seen.	The tops of three cooling towers and stacks could be visible in distance silhouetted against the sky.
Color	Not seen.	Not seen.	Would blend in fairly well, although stacks could be visible in the distance.
Texture	Not seen.	Not seen.	Too far to see texture.
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	4	4	3
Line	4	4	3
Color	4	4	3
Texture	4	4	4

Does design meet VRM Class management objectives? Yes for VRM Class III.

Explain: Other than the tops of the three cooling towers and stacks (which would be 15 miles away), none of the Alternative 1 site would be seen from KOP 2.

Additional mitigation measures recommended. None.

White Pine Project *Visual Contrast Rating Worksheet: Alternative 1* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Alternative 1**		
KOP	**KOP 3: Lincoln Highway**		
VRM Class	**VRM Class III**		
Distance From KOP	**Approximately 7 miles away**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	KOP too far away to notice changes to site.	KOP too far away to be able to see disturbed vegetation.	Inverted cylindrical shape of the cooling towers would be visible as would some long horizontal facilities (coal storage areas and storage berms) and some long vertical facilities (stacks).
Line			Inverted cylindrical shape of the cooling towers would be visible as would stacks and some long horizontal facilities (coal storage areas and storage berms).
Color	Brownish – gray earth colors.	Sage green and grays.	The untreated concrete of the three cooling towers would be noticed and would contrast to some degree with the adjacent landscape and sky. Other facilities that would be painted earth tones to reduce visual impacts would be less visible.
Texture			The smooth concrete of the cooling towers might be noticeable. The texture of facilities would not be noticed much from this distance.
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	4	4	3
Line	4	4	3
Color	4	4	3
Texture	4	4	3
Does design meet VRM Class management objectives? Yes for Class III. **Explain:** Changes to the viewed landscape from this KOP would be low, which would exceed the objectives of VRM Class III. **Additional mitigation measures recommended.** No.			

White Pine Project *Visual Contrast Rating Worksheet: Alternative 1* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Alternative 1**		
KOP	**KOP 4: Highway 93 (at a turnoff)** [Simulation developed for this KOP]		
VRM Class	**VRM Class III**		
Distance From KOP	**Approximately 1 mile**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	Alternative 1 facilities would visually interrupt the extensive flat plane of the valley floor (as does the highway).	Vegetation would be removed and replaced with facilities and cleared areas.	The facility structures would be very apparent from this location and would introduce new geometric forms into the seen landscape.
Line	The coal storage and berms for the evaporation pond and waste storage areas would introduce long horizontal shapes to the landscape.		The cooling towers and stacks would add large vertical "lines" to the landscape that would be silhouetted against the sky from this location.
Color	The dark color of the coal being stored would contrast with the surrounding landscape.		The untreated concrete of the three cooling towers and the colors of other project facilities would contrast with the adjacent landscape and sky and would be very noticeable.
Texture			The texture of the facilities would be courser than that of the nearby landscape.
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	1	2	1
Line	1	3	2
Color	2	3	2
Texture	3	3	3

White Pine Project
Visual Contrast Rating Worksheet: Alternative 1
EDAW/CH2M HILL

Does design meet VRM Class management objectives? Yes.

Explain: Objectives for Class III lands include partially retaining the existing character of the landscape and keeping the level of change to a characteristic landscape moderate. Although the scale of the proposed project's facilities would make them quite visible from U.S. 93, the facilities would be located west of the highway and would not block north, east, or west views of Steptoe Valley from the highway. VRM Class III objectives would be met from this location.

Additional mitigation measures recommended. None.

White Pine Project *Visual Contrast Rating Worksheet: Alternative 1* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Alternative 1**		
KOP	**KOP 5: McGill**		
VRM Class	**VRM Class III**		
Distance From KOP	**Approximately 10.5 miles north**		
Proposed Activity Description: **Power Plant**			
	Land/Water	**Vegetation**	**Structures**
Form	Flat land would be cleared, but would require relatively little grading. Area would be rectangular in shape. KOP too far away to notice.	Site vegetated with sage brush community plants would be cleared. KOP too far away to be able to see disturbed vegetation.	The tops of the three cooling towers (and stacks) could be seen silhouetted above the mountains surrounding Steptoe Valley from this location. A variety of large-scale block-like and angular forms of project various facilities would be visible from this KOP.
Line			Inverted cylindrical shape of the cooling towers would be visible.
Color	Brownish – gray earth colors.	Sage green and grays.	The untreated concrete of the three cooling towers would be noticed and would contrast to some degree with the adjacent landscape and sky. Other facilities that would be painted earth tones to reduce visual impacts would be less visible.
Texture			The smooth concrete of the cooling towers might be noticeable. The texture of facilities would not be noticed much from this distance.
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	4	4	2
Line	4	4	3
Color	4	4	3
Texture	4	4	4
Does design meet VRM Class management objectives? Yes. **Explain:** Changes to the viewed landscape from this KOP would be low, which would exceed the objectives of VRM Class III. **Additional mitigation measures recommended.** No.			

White Pine Project *Visual Contrast Rating Worksheet: Alternative 1* **EDAW/CH2M HILL**			
Project Name	**White Pine**		
Alternative	**Alternative 1**		
KOP	**KOP 6: Highway 50**		
VRM Class	**VRM Class III**		
Distance From KOP	**Within ¼ mile**		
Proposed Activity Description**: Transmission line**			
	Land/Water	**Vegetation**	**Structures**
Form	Same as Proposed Action	Same as Proposed Action	Same as Proposed Action
Line	Same as Proposed Action	Same as Proposed Action	Same as Proposed Action
Color	Same as Proposed Action	Same as Proposed Action	Same as Proposed Action
Texture	Same as Proposed Action	Same as Proposed Action	Same as Proposed Action
Degree of Contrast **1 = Strong;** **2 = Moderate;** **3 = Weak; 4 = None**	**Land/Water**	**Vegetation**	**Structures**
Form	Same as Proposed Action	Same as Proposed Action	Same as Proposed Action
Line	Same as Proposed Action	Same as Proposed Action	Same as Proposed Action
Color	Same as Proposed Action	Same as Proposed Action	Same as Proposed Action
Texture	Same as Proposed Action	Same as Proposed Action	Same as Proposed Action
Does design meet VRM Class management objectives? Same as Proposed Action. **Explain:** Same as Proposed Action. **Additional mitigation measures recommended.** None.			

Appendix O

Programmatic Agreement

Doris M.

STATE OF NEVADA

DEPARTMENT OF CULTURAL AFFAIRS

Nevada State Historic Preservation Office

100 N. Stewart Street

Carson City, Nevada 89701

(775) 684-3448 • Fax (775) 684-3442

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KENNY C. GUINN
Governor

SCOTT K. SISCO
Interim Director

RONALD M. JAMES
State Historic Preservation Officer

Bureau of Land Management
JUN 08 2006
RECEIVED
Ely, NV

April 25, 2006

Gene A. Kolkman
Field Manager
Ely Field Office
Bureau of Land Management
HC 33 Box 33500
Ely, NV 89301-9408

Dear Mr. Kolkman:

Please find enclosed the programmatic agreement regarding the White Pine Energy Station Project. I have reviewed and signed the agreement. The only remaining task is to file a copy with the Advisory Council.

The agreement is well written and easy to understand. I would like to take this opportunity to commend Nate Thomas, archaeologist on your staff, for the hard work and the good results. We look forward to working with your staff on this project.

Sincerely,

Alice M Baldrica

ALICE M. BALDRICA, Deputy
State Historic Preservation Officer

Enc

**PROGRAMMATIC AGREEMENT
AMONG
THE DEPARTMENT OF THE INTERIOR,
BUREAU OF LAND MANAGEMENT, ELY DISTRICT, NEVADA
AND
THE NEVADA STATE HISTORIC PRESERVATION OFFICER
REGARDING THE WHITE PINE ENERGY STATION PROJECT**

WHEREAS, the BLM is considering an application for rights of way and a land disposal for the White Pine Energy Station (WPES) proposed by White Pine Energy Associates, LLC (WPEA) in White Pine County, Nevada, and the BLM is preparing an Environmental Impact Statement for this proposed project;

WHEREAS, WPEA has been invited to participate in consultation and to concur in this Programmatic Agreement;

WHEREAS, the BLM has invited the Advisory Council on Historic Preservation (Advisory Council) to participate in consultation and the Advisory Council has declined this invitation;

WHEREAS, the BLM has determined that the construction and installation of the WPES (the undertaking) may have an effect upon properties eligible for inclusion in the National Register of Historic Places (NRHP), and has consulted with the Nevada State Historic Preservation Officer (SHPO) pursuant to the Nevada BLM/SHPO Protocol for implementing Section 106 of the National Historic Preservation Act (NHPA);

WHEREAS, this Programmatic Agreement covers all aspects of planning, construction, and installation of the undertaking, including but not limited to, electric generation station, power and communication transmission systems, water wells and pipelines, rail spur, staging areas and access roads, the construction zone, extra work areas, and all ancillary facilities;

NOW THEREFORE, the SHPO and the BLM agree that development of the WPES shall be administered in accordance with the following stipulations to ensure that historic and prehistoric properties will be treated to avoid or mitigate effects to the extent practicable, regardless of surface ownership, and to satisfy the BLM's Section 106 responsibilities for all aspects of the undertaking.

AREA OF POTENTIAL EFFECT

WPEA proposes to construct an energy station, electric distribution and transmission lines, substations, water lines, water wells, a rail spur and associated facilities such as access roads.

The Area of Potential Effect (APE) shall be defined to include all potential direct and indirect effects to historic properties and Traditional Cultural Properties from any WPEA activities associated with the undertaking. The APE shall include areas of direct effect, although not an

inclusive list, such as the 200-foot-wide transmission line corridor, the electric generation station site, water well sites, substation sites, and other areas involving ground disturbance such as new or improved access roads and other project facilities located outside the transmission line corridor. The APE for rail spurs and water line corridors shall be 300 feet wide. The APE for new and improved access roads outside the transmission line corridor and for new electric distribution lines outside the water line corridor shall be 100 feet wide.

The APE for assessing indirect effects on historic properties will extend one mile from the transmission line corridor and two miles from the proposed electric generation station sites. Indirect effects on historic properties such as the Lincoln Highway, the Nevada Northern Railroad, and the Pony Express Trail shall be addressed per the guidance in Instruction Memoranda No. NV-2004-004 and No. NV 2004-006.

The initial specific APE is mapped on Figure 1. At the discretion of the BLM, the APE may be amended as needed and any amendments will be handled under the terms of this agreement.

STIPULATIONS

A. Identification

1. The BLM shall identify interested persons and tribes pursuant to the BLM/SHPO Protocol and the NEPA process (36 CFR 800.8) and involve them, as appropriate, in activities associated with the undertaking. Proprietary cultural resource information data sharing will be contingent upon data sharing agreements, which guarantee appropriate protection of confidential information.

2. The BLM, in consultation with the SHPO, shall ensure that a Class III inventory of all proposed project facilities shall be completed prior to construction.

3. Required inventory shall be completed regardless of the ownership (public or private) of the lands involved and WPEA shall be responsible for gaining access to privately held lands.

4. In areas of direct effect where the ground is heavily disturbed to a depth of greater than 36 inches below the ground surface, or in areas where access is dangerous to survey personnel, portions of the APE may be exempted from Class III inventory in consultation with the BLM.

5. The BLM shall consult with appropriate tribes to identify properties considered to be of traditional religious and cultural importance in areas that would be directly or indirectly affected by the WPES.

6. The BLM shall have the consulting archaeologists use the *Ely Resource Management Plan Planning Model* and the *Great Basin Restoration Initiative: Cultural Resources*

Landscape Level Planning Model to identify locations, types, and sensitivity of historic properties anticipated to be affected by the WPES. The findings from this review shall be used to prepare a report on expected archaeological sites in the APE and develop predictions that shall be compared to the actual findings when Class III inventories are conducted.

7. An isolated find is defined as a single artifact, pieces from a single artifact, or unassociated feature. Isolates will be recorded sequentially and listed within the inventory report on a table with IF number, location and description, and plotted on a separate isolated find map within the Class III report.

8. Non-linear sites extending out of the APE for direct effects shall be recorded in their entirety with the exception of very large sites such as town sites, mining complexes, continuous stream/lake terrace sties, or extensive prehistoric quarries or habitation sites. These exceptions shall be approved in advance by the BLM.

9. Linear resources (e.g., railroads, roads, trails, ditches, etc.) crossing and extending beyond the APE for direct effects shall be divided into three groups:

a. Roads or linear features with no mention in the BLM Field Office records or included on General Land Office (GLO) plats, no associated features or dateable artifacts, or which have lost all integrity through extensive blading will not be recorded;

b. Roads, linear features, or other resources included on GLO plats but which are not associated with features or dateable artifacts, and do not appear to be significant on the basis of known archival data shall be treated as "isolated linear segments." These resources shall be recorded in tabular form and collected data shall include a minimum of two (2) separate GPS points at each end of the linear feature within the APE;

c. Roads or other linear features included on GLO plats (especially named roads) or features known from other archival data to be potentially significant, or which have associated features or dateable artifacts, shall be recorded on IMACS site forms.

10. The BLM shall have the consulting archaeologists conduct records searches of GLO plat maps, the National and State Registers of Historic Places, the National Trail System, and conduct a Class I inventory of agency archives to locate potential historic properties within the APE for direct and indirect effects.

a. An inventory and photo documentation of historic ranches that potentially may be affected by the undertaking shall be conducted. This inventory shall include ranch complexes greater than 45 years of age where project-related actions (e.g., new overhead transmission lines) could adversely affect the historic setting,

feeling, and association of these properties. This inventory shall involve documentation of each historic ranch property within one mile of the proposed project, including a historic context (date established, individuals involved, etc.). Documentation of architectural resources shall be obtained from public roads. Information on project-related impacts to these properties shall be based on visual resource assessments prepared for the EIS.

b. An inventory of historic properties along and the landscape adjacent to the segment of the Nevada Northern Railroad to be improved within White Pine and Elko Counties shall be conducted.

c. An inventory of the segments of the Pony Express Trail, the Lincoln Highway, and the Nevada Northern Railroad within the significant viewshed of the WPES, including ancillary facilities, shall be conducted using photographs and visual resource assessments prepared for the EIS. Guidance in Instruction Memoranda No. NV-2004-004 and No. NV-2004-006 relative to the Pony Express Trail will be followed.

B. Eligibility

1. The BLM, in consultation with the SHPO, shall ensure that all cultural resources located within the APE of an activity area are evaluated for eligibility to the NRHP prior to the initiation of activities that may affect historic properties. Eligibility will be determined in a manner compatible with the BLM/SHPO Protocol.

2. To the extent practicable, eligibility determinations shall be based on inventory information. If the information gathered in the inventory is inadequate to determine eligibility, the BLM or WPEA (through its contractors) may need to conduct limited subsurface testing, or other evaluative techniques, to determine eligibility. Subject to approval by the BLM, in consultation with the SHPO, evaluative testing is intended to provide the minimum data necessary to define the nature, density, and distribution of materials in potential historic properties, to make final evaluations of eligibility, and to devise treatment options responsive to the information potential of the property. Should the BLM disapprove the applications for the WPES project, or should WPEA abandon the project and withdraw its applications prior to the BLM approval, then any further evaluative testing shall cease, except for completing all fieldwork and post-fieldwork activities that are ongoing as of the date of withdrawal or disapproval.

3. If any of the parties disagree regarding eligibility, the BLM shall notify all parties and seek a determination of eligibility from the SHPO. If the BLM and SHPO disagree regarding eligibility, the BLM shall seek a formal determination of eligibility from the Keeper of the National Register in accordance with 36 CFR 800.4 (dated 1986). The Keeper's determination will be considered final.

4. If an Indian tribe that attaches religious and cultural significance to a property disagrees with the BLM's findings, the tribe may ask the Advisory Council to request that the agency official obtain an official determination of eligibility from the Keeper of the National Register.

C. Treatment

1. In avoiding or mitigating effects, the BLM, in consultation with SHPO, Indian tribes, and interested persons, shall determine the precise nature of effects to historic properties identified in the APE if the WPES project is approved by the BLM. All treatment shall be done in a manner consistent with the BLM/SHPO Protocol.

2. The BLM, to the extent practicable, and in consultation with the SHPO, shall ensure that WPEA avoids effects to historic properties through project design, or redesign, relocation of facilities, or by other means in a manner consistent with the BLM/SHPO Protocol.

3. When avoidance is not feasible, the BLM, in consultation with SHPO, Indian tribes, WPEA, and interested persons, shall develop, or ensure that WPEA develops, an appropriate treatment plan designed to lessen or mitigate project-related effects to historic properties. For properties eligible under criteria (a) through (c) (36 CFR 60.4), mitigation, other than data recovery, may be considered in the treatment plan (e.g. HABS/HAER recordation, oral history, historic markers, exhibits, interpretive brochures or publications, etc.). Where appropriate, treatment plans shall include provisions (content and number of copies) for a publication for the general public.

4. When data recovery is required as a condition of approval, the BLM, in consultation with the SHPO, shall develop, or ensure that WPEA develops, a data recovery plan that is consistent with the Secretary of the Interior's Standards and Guidelines for Archaeology and Historic Preservation (48 FR 44716-37) and *Treatment of Historic Properties: A Handbook* (Advisory Council 1980).

5. The BLM shall require as a condition of approval and implement, or ensure that WPEA implements, through its contractor, the fieldwork portions of any final treatment plan prior to initiating any activities that may affect historic properties.

6. The BLM shall ensure that all records and materials resulting from identification and treatment efforts are curated in accordance with 36 CFR 79 in BLM-approved facilities. All materials collected will be maintained in accordance with 36 CFR 79 until the final treatment report is complete and collections are curated or returned to their owners. The BLM shall encourage private owners to donate collections obtained from their lands to an appropriate curation facility.

7. The BLM shall ensure that all final reports resulting from treatment activities will be provided to the SHPO, Indian tribes, and the Advisory Council, and made available to

other interested persons. All such reports shall be consistent with contemporary professional standards and the Department of Interior's Formal Standards for Final Reports of Data Recovery Programs (42 FR 5377-79).

D. Discovery Situations

1. When previously unidentified cultural resources are discovered, all WPES-related activities within 100 meters of the discovery will cease immediately and WPEA or its authorized representative shall notify the BLM authorized officer. Prior to initiating any ground disturbing activities within the APE, WPEA will provide the parties with a list of, and schedule for, the WPEA and/or other authorized employees empowered to halt all potentially destructive activities in discovery situation and who will be responsible for notifying the BLM of any discoveries. At least one of these employees will be present during all of WPEA's activities.

a. The BLM shall notify the SHPO, interested persons and Indian tribes and consider the SHPO's and tribe's initial comments on the discovery. Within two working days of the discovery, the BLM shall notify WPEA, the SHPO, Indian tribes, and identified interested persons of the BLM's decision to either allow undertaking-related activities to proceed or to require mitigation.

b. If, in consultation with the SHPO, interested persons and Indian tribes, the BLM determines that mitigation is appropriate, the BLM shall solicit comments from the SHPO, Indian tribes, and interested persons, as appropriate, to develop mitigating measures. The SHPO, tribes, and other interested persons, as appropriate, will be allowed two working days to provide the BLM with comments to be considered when the BLM makes a decision on extent of mitigative efforts. The BLM will determine the mitigation required; within seven working days of the BLM's notification to WPEA of the need for mitigation, the BLM will notify the SHPO, Indian tribes, and appropriate interested persons of its decision and ensure that such mitigative actions are implemented.

c. The BLM shall ensure that reports of mitigation efforts for discovery situations are completed in a timely manner and conform to the Department of Interior's Formal Standards for Final Reports of Data Recovery Program (42 FR 5377-79). Drafts of such reports shall be submitted to the SHPO and Indian tribes for a 30 -day review and comment as stipulated in H.2. Final reports shall be submitted to the SHPO, Indian tribes, Advisory Council, and interested persons for informational purposes.

d. All activities in the area of the discovery will be halted until WPEA is notified in writing by the BLM that mitigation is complete and activities can resume.

E. Other Considerations

1. The BLM shall ensure that all stipulations of this Agreement are carried out by the BLM, SHPO, WPEA, and all of its contractors or other personnel.

2. The BLM shall ensure that historic, architectural, ethnographic, and archaeological work conducted pursuant to this Agreement is carried out by, or under the direct supervision of, persons meeting qualifications set forth in the Secretary of the Interior's Professional Qualification Standards (36 CFR 61) and who have been permitted for such work on public lands, by the BLM.

3. WPEA, in cooperation with the BLM and the SHPO, shall ensure that all its personnel, and all the personnel of its contractors, are directed not to engage in the illegal collection of historic and prehistoric materials. WPEA shall cooperate with the BLM to ensure compliance with the Archaeological Resources Protection Act of 1979 (16 U.S.C. 470) on public lands and with Nevada Revised Statutes 381 (Nevada Antiquities Law) for state and private lands.

4. WPEA shall bear the expense of identification, evaluation, and treatment of all cultural properties directly or indirectly affected by WPES project-related activity. Such costs shall include, but not be limited to, pre-field planning, field work, post-fieldwork analysis, research and report preparation, interim and summary report preparation, publications for the general public, and the cost of curating project documentation and artifact collections. It is understood that the BLM may decide not to approve the right-of-way (ROW) and land disposal applications for the WPES. Prior to any BLM decision to approve or disapprove the applications, WPEA has agreed to bear the expense of the identification and evaluation of cultural properties required as part of the cultural resources surveys necessary to obtain information for the Environmental Impact Statement. If the BLM disapproves the applications, or if WPEA abandons or withdraws its pending application for ROW and land disposal prior to a BLM decision, then WPEA shall incur no further expense for evaluation or treatment for any cultural properties except for completing existing or already authorized work (fieldwork and post-fieldwork activities) that is ongoing as of the date of withdrawal or disapproval.

5. Identification, evaluation, and treatment efforts may extend beyond the geographic limits of the ROW when the resources being considered extend beyond the ROW. No identification, evaluation, or treatment efforts will occur beyond that necessary to gather data for the completion of the Section 106 process as agreed, prior to the BLM's decision to approve or disapprove the submitted applications.

6. Traditional Cultural Properties (TCPs) will be identified, evaluated, and treated through consultation with appropriate Indian tribes. WPEA can contract for data gathering to assist the BLM in identifying, evaluating and treating TCPs. However, formal consultation, as needed, will be done by the BLM. TCP identification, evaluation

and treatment efforts shall be consistent with BLM Manual 8160 and its associated handbook.

7. Information on the location and nature of all cultural resources, and all information considered to be proprietary by tribes, will be held confidential to the extent provided by the NHPA, the Native American Graves Protection and Repatriation Act (NAGPRA), Archaeological Resources Protection Act (ARPA) and other applicable Federal laws

8. The BLM shall ensure that any human remains, grave goods, items of cultural patrimony, and sacred objects, encountered during the undertaking are treated with the respect due such materials. In coordination with this Agreement, human remains and associated grave goods found on public land will be handled according to the provisions of NAGPRA and its implementing regulations (43 CFR 10). Human remains and associated grave goods found on state or private land will be handled according to the provisions of Nevada statute NRS 383.

F. Monitoring

1. The BLM and the SHPO may monitor actions carried out pursuant to this Agreement.

2. Any areas that the BLM, in consultation with the SHPO, identifies as sensitive will be monitored by an appropriate professional cultural resource specialist or tribal representative during any activities that may impact the area. Treatment Plans will contain monitoring plans as needed. Monitors shall be empowered to stop work to protect resources. Work cannot proceed without monitors in place (including Native American monitors as appropriate).

G. Notices to Proceed

If the BLM decides to approve the submitted applications, the ROWs issued under these applications shall provide for the issuance of Notices to Proceed. Notices to Proceed (NTP) may be issued by the BLM to WPEA for individual construction activities as defined by WPEA in its Construction Plan under any of the following conditions:

1. The BLM and SHPO have determined that there are no cultural resources within the APE for the construction segment;

2. BLM and SHPO have determined that there are no historic properties within the APE for the construction segment; or

3. BLM, after consultation with the SHPO, Indian tribes, and interested persons, has implemented an adequate treatment plan for the construction segment, and

(a) fieldwork phase of the treatment option has been completed;

(b) BLM has accepted a summary description of the fieldwork performed and a reporting schedule for that work; and

(c) WPEA has posted a surety as stipulated in Section I. below for post-fieldwork costs of the treatment plan.

H. Time Frames

1. Reports: The BLM shall review and comment on any report submitted by WPEA within 30 calendar days of receipt.

2. Consultation with Interested Parties and Indian tribes: Prior to SHPO consultation, the BLM shall submit the results of all identification and evaluation efforts and treatment plans to identified Indian tribes and interested persons for a 30-day review and comment period. Consultation for discovery situations shall be handled in accordance with Section D.

3. SHPO Consultation: The BLM shall submit the results of all identification and evaluation efforts and treatment plans to the SHPO for a 30-day review and comment period. Consultation for discovery situations shall be handled in accordance with Section D.

4. If any party to the agreement, Indian tribe, or other interested person fails to respond to the BLM within 30 days of the receipt of a submission, the BLM shall presume concurrence with the BLM's findings and recommendations as detailed in the submission and proceed accordingly.

5. Reports: A draft final report of all identification, evaluation, treatment or other mitigative activities will be due to the BLM within nine (9) months after the completion of the fieldwork associated with the activity, unless otherwise negotiated.

6. Curation: All records, photographs, maps, field notes, artifacts, and other materials collected or developed for any identification, evaluation, or treatment activities will be curated in a facility approved by the BLM at the time the final report associated with that activity is accepted by the BLM, unless materials and artifacts must be returned to the owner.

I. Surety Bonds

1. The terms of any ROW issued by the BLM for the WPES shall provide for the posting of sureties for the protection of cultural properties, as set forth below. WPEA will post a surety with the BLM in an amount sufficient to cover all post-fieldwork costs associated with implementing a treatment plan or other mitigative activities, as negotiated by WPEA when they contract for services in support of this Agreement. Such costs may include, but are not limited to post-field analyses, research and report preparation, interim and

summary reports preparation, and the curation of project documentation and artifact collections in a BLM-approved curation facility. The surety shall be posted prior to the BLM issuing any Notice to Proceed.

2. The surety posted as provided in Section I (1) above shall be subject to forfeiture if the post-fieldwork tasks are not completed within the time period established by the treatment option selected; provided, however, that the BLM and WPEA may agree to extend any such time periods. The BLM shall notify WPEA that the surety is subject to forfeiture and shall allow WPEA 15 days to respond before action is taken to forfeit the surety.

3. The surety shall be released, in whole or in part, as specific post-fieldwork tasks are completed and accepted by the BLM.

J. Dispute Resolution

1. If any party to this agreement, or an interested person, objects to any activities proposed pursuant to the terms of this agreement, the BLM shall consult with the objecting party and the SHPO to resolve the issue. The BLM Nevada State Office will have the authority to make a final determination for any objection that cannot be resolved by local consultation.

2. The Parties may continue all actions under this Agreement that are not the subject of the dispute.

K. Amendment

Any party to this Agreement may request that this Agreement be amended, whereupon the Parties will consult to consider such amendment.

L. Termination

Any party to this Agreement may terminate the Agreement by providing thirty (30) days notice to the other Parties, provided that the Parties will consult during the period prior to termination to seek agreement on amendments or other actions that would avoid termination.

M. Execution

1. Execution and implementation of this Agreement evidences that the Parties have satisfied their Section 106 responsibilities for all actions associated with the construction and installation of the WPES.

2. In the event that the Parties do not carry out the requirements of this Agreement or it is terminated, the BLM will comply with the provisions of the BLM/SHPO Protocol.

3. This Agreement shall become effective on the date of the last signature below, and shall remain in effect until terminated as provided in Stipulation L, or until undertaking is completed, or a maximum of five years from the effective date.

CONSULTING PARTIES:

BUREAU OF LAND MANAGEMENT, ELY DISTRICT, NEVADA

By: Joyce A Kolb Date: 3/2/06

Title: Field Manager

NEVADA STATE HISTORIC PRESERVATION OFFICE

By: Alice M Baldrica Date: 4/25/06

Title: Deputy SHPO

CONCURRING PARTY:
White Pine Energy Associates, LLC

By: Paul M. Rosser Date: 3/9/06

Title: Exec. V.P

APPENDIX A: CONTRUCTION SEGMENTS

Construction Segments

Construction segments for the WPES for the purposes of issuing Notices to Proceed are defined as follows:

The following construction segments are associated with the water system (including water pipe, wells, and associated access roads and electric distribution lines).

Segment A1 –Water system from power plant site to farthest outlying well.
Segment A2 – Electric distribution line from Gonder substation to Segment A1 (if required).

The following construction segments are associated with the power plant site, electric system, and associated project access facilities.

Segment B1 – Power plant site and new access road.
Segment B2 – New rail spur between Nevada Northern Railroad and power plant site.
Segment C1 – Duck Creek Substation and new access road.
Segment C2 – Thirtymile Substation and new access road.
Segment C3- Electric transmission between Duck Creek and Thirtymile substations, including associated access roads and laydown/staging areas.
Segment C4 – Electric connection (looping) between Falcon-Gonder transmission line and Thirtymile Substation.

Figure 1 - Proposed Action White Pine Energy Station

Appendix P

Cultural Resources Background Information

APPENDIX P

Cultural Resources Background Information

This appendix contains cultural resources background information on regulatory setting, criteria for significance, and the natural and cultural settings in the affected environment of the proposed WPES Project. Information in this appendix supports discussions contained in Section 3.13, *Cultural Resources* in Chapter 3 of this EIS.

Regulatory Setting

Historical and archaeological resources are managed under an intricate system of federal laws, some of which have resulted in comprehensive plans or management strategies. Those that pertain specifically to historic and archaeological resources and the WPES Project are briefly summarized in the following text.

Historic Sites Act of 1935 (16 USC 461-467)

The Historic Sites Act established a national policy to preserve for public use historic sites, buildings, and objects of national significance for the inspiration and benefit of the people of the United States, and led to the implementation of the Historic American Building Survey (HABS) and the Historic American Engineering Record (HAER) by the Secretary of the Interior and the National Park Service. This Act also created a National Park System Advisory Board, which in part was responsible for making recommendations on the designation of national historic landmarks.

National Environmental Policy Act (NEPA) of 1969 (42 USC 4321 et seq.)

The NEPA declared, in part, that it is the policy of the federal government to preserve important historic, cultural and natural aspects of the nation's heritage, and requires federal agencies to prepare environmental impact statements prior to making decisions about projects that may significantly affect the quality of the human environment. The Council on Environmental Quality is responsible for issuing guidelines for the implementation of this broad act.

Executive Order 11593, Cultural Resources

On May 31, 1971, the President of the United States issued an Executive Order directing all federal agencies to locate and inventory all cultural resources under their jurisdiction to ensure that actions do not inadvertently affect significant cultural resources. This Order further directed agencies to consider the effects of actions authorized by federal permits or licenses on resources located on non-federal lands.

American Indian Religious Freedom Act of 1978 (PL 95-341)

The American Indian Religious Freedom Act established federal policy to protect and preserve the inherent rights of freedom for native groups to believe, express, and exercise their traditional religions. These rights included, but are not limited to, access to sites, use

and possession of sacred objects, and the freedom to worship through ceremonials and traditional rites.

Executive Order 13007, Indian Sacred Sites

On March 24, 1996, the President of the United States issued an Executive Order mandating that in managing federal lands, each executive branch agency with statutory or administrative responsibility for the management of federal lands shall, to the extent practicable permitted by law, and not clearly inconsistent with essential public functions, (1) accommodate access to and ceremonial use of Indian sacred sites by Indian religious practitioners and (2) avoid adversely affecting the physical integrity of such sacred sites. Where appropriate, agencies are required to maintain the confidentiality of sacred sites.

National Historic Preservation Act (NHPA) of 1966 (16 USC 470 et seq.)

The NHPA established the Advisory Council on Historic Preservation (ACHP); authorized the Secretary of the Interior to maintain a NRHP; directed the Secretary to approve state historic preservation programs that provided for a SHPO; established a National Historic Preservation Fund program; and codified the National Historic Landmarks program.

Section 106 of the NHPA requires that federal agencies take into account the effects of their actions on properties that may be eligible for or listed on the NRHP, and afford the ACHP a reasonable opportunity to comment. To determine if an undertaking could affect NRHP-eligible properties, all cultural sites (including archaeological, historical, and architectural properties) that could be impacted by the undertaking must be inventoried and evaluated for inclusion in the NRHP.

The Section 106 review process (36 CFR 800) is implemented using a five-step procedure: 1) the responsible federal agency (which is the BLM) or the designated federal representative (as authorized by the BLM, may be the Licensee) initiates the Section 106 process through contact with the appropriate SHPO, establishes the APE, identifies other consulting and interested parties, and begins public involvement; 2) identification and evaluation of historic properties within the APE; 3) assessment of the effects of the undertaking on properties that are eligible for the NRHP; 4) consultation with the SHPO, concerned parties, and other agencies to resolve adverse effects and the development of an Agreement Document (Memorandum of Agreement or Programmatic Agreement) that addresses the treatment of historic properties, if appropriate; and 5) implementation according to the conditions of the Agreement Document. The Section 106 compliance process need not consist of all the steps above, depending on the situation. For example, if identification and evaluation result in the documented conclusion that no properties included in, or eligible for inclusion in, the NRHP are present within the APE, the process ends with the identification and evaluation step.

Archaeological Resources Protection Act of 1979 (16 USC 470aa-mm)

The Archaeological Resources Protection Act amended the Antiquities Act of 1909, set a broad policy that archaeological resources are important to the nation and should be protected, and required special permits prior to the excavation or removal of archaeological resources from public or Indian lands. The purpose of this Act was to secure, for the present and future benefit of the American people, the protection of archaeological resources and

sites that are on public lands and Indian lands, and to foster increased cooperation and exchange of information among governmental authorities, the professional archaeological community, and private individuals having collections of archaeological resources and data that were obtained before October 31, 1979.

Criteria for Significance

Decisions regarding the management of cultural sites hinge on determinations of their NRHP significance. To determine significance, the National Park Service has identified components that must be considered in the evaluation process. These include criteria for determining eligibility, historic context, and integrity.

Significance of cultural resources is measured against the following NRHP criteria for evaluation (36 CFR 60.4):

> The quality of significance in American history, architecture, archeology, engineering, and culture is present in districts, sites, buildings, structures, and objects that possess integrity of location, design, setting, materials, workmanship, feeling, and association, and,
>
> (a) that are associated with events that have made a significant contribution to the broad patterns of our history; or
>
> (b) that are associated with the lives of persons significant in our past; or
>
> (c) that embody the distinctive characteristics of a type, period, or method of construction, or that represent the work of a master, or that possess high artistic values, or that represent a significant and distinguishable entity whose components may lack individual distinction; or
>
> (d) that has yielded, or may be likely to yield, information important in prehistory or history.

Period of Significance

The concept of a period of significance as used in the evaluation process establishes the timeframe in which a property was associated with important events, activities, or persons; or the period in history when it attained the characteristics that qualify it for NRHP eligibility. Period of significance usually begins with the date events began giving the property its historic significance or the date of construction. Periods of significance may be as brief as a single year or they may span several years, and consist of beginning and close dates (National Register Bulletin 16A, 1997).

Application of the NRHP Criteria to Historic-era Properties

While historic-era properties may be found eligible to the NRHP under any of the above criteria, some criteria are more commonly relevant than others. Often, historic-era properties are found eligible under Criterion A, for a significant association with a historic event, or under Criterion C, for displaying distinctive examples of a particular architectural style. Potential significance is evaluated in direct relation to the contextual themes identified as

being relevant to a particular region. A detailed description of the criteria and their application follows.

Criterion A

For a historic-era property to be eligible under Criterion A, it must be found to be associated with specific important events (for example, primary exporter of cattle in the state) or important patterns of events (for example, development of irrigated farming or transportation). A building or property must not only be associated with a historic event, but also be adequately documented through an accepted means of research; speculative associations alone cannot confer eligibility. The significance of the documented association must then be demonstrable. In other words, the property's association with the important event must also be an important association in and of itself, not mere coexistence.

Criterion B

For eligibility under Criterion B, a property must be associated with an important individual's productive life, and must be a property that is closely associated with that person. For instance, a property that was once owned or established by a prominent citizen, but was not their primary place of employment or habitation, or had no other known associations to the person, would not likely be found eligible under Criterion B. Determining associations with people considered important in local history would require a careful assessment of whether the property under investigation is the property that best represents that association.

Criterion C

Significance under Criterion C usually stems from the ability of the property, or one of more of its buildings, constructed facilities or structures, to illustrate a subtype associated with the historic context and the period of significance. Just as importantly, the property should retain enough integrity to convey that association. Generally under this Criterion, a property will appear eligible because it is comprised of constructed features that exhibit especially fine style, craftsmanship, construction methods, or is a good representative of a relatively rare architectural or engineering style for the period.

Criterion D

Eligibility under Criterion D hinges on the ability of the property, as contained in artifacts and objects, to further address issues of scientific importance to the period of significance. These data are primarily derived from archaeological deposits, and rarely buildings and structures themselves. Archaeological features or deposits may provide new information not available elsewhere regarding kinds of documented or undocumented activities. While constructed elements can sometimes provide important information regarding historic construction techniques, most of these techniques are well documented in both written and visual sources, and generally, would not yield new primary information.

Historic Landscape Considerations

Research into historic landscape issues was guided by National Register Bulletin 30, Guidelines for Evaluating and Documenting Rural Historic Landscapes (National Park Service, 1999), the Secretary of the Interior's Standards for the Treatment of Historic

Properties with Guidelines for the Treatment of Cultural Landscapes (1992), and the NRHP eligibility criteria. These guidelines and regulations, along with the developed eligibility considerations outlined below, provided a framework with which to conduct a preliminary assessment of the potential significance of the subject properties as historic vernacular landscapes. The evaluation of such landscapes should include the assessment of whether the property:

- Played an important role in the region's economic development during the period of significance;
- Is a rare example of a property type or the oldest example of its kind in the area;
- Is a good representation of a property within a particular historic theme;
- Comprises features that indicate unique innovations or adaptations in a specific area development;
- Retains the characteristics of a property, within the period of significance.

District Considerations

A district derives its importance from being a unified entity resulting from the shared interrelationship of its resources or elements (National Register Bulletin 15). A district must be a definable geographic area that can be distinguished from surrounding properties by changes in scale, age, type and style; or by documented differences in the historic development of the district from surrounding properties. It is seldom, however, defined by the limits of current parcel ownership, or by planning boundaries. The boundaries of a historic district must be based upon a shared relationship among the properties constituting the district

Integrity

Generally, integrity refers to the general character and feeling of the site and the degree to which it currently resembles its condition and setting during its period of significance. Historic integrity is composed of seven qualities: location, design, setting, materials, workmanship, feeling, and association (National Park Service, 1999). Assessment of the property in relation to these seven aspects requires an appraisal of whether subsequent changes in the property contribute to its historic evolution or alter its historic integrity from that of the period of significance.

Because of the importance of land, natural features, and vegetation, the seven qualities of integrity are applied differently to rural landscapes. This relationship involving patterns of spatial organization, circulation networks, and clusters is directly related to design and is strongly influenced by the cohesiveness of the rural landscape. Integrity of setting and design is composed of boundary demarcations, small-scale elements, vegetation, evidence of responses to the natural environment, continuing or compatible land uses, and activities that enhance integrity of feeling and association. Associated archaeological deposits may enhance the integrity if they provide evidence of activities no longer practiced.

Assessing Overall Integrity

Generally, integrity is based on the condition of the overall property and its ability to convey significance. In assessing the overall integrity, it is necessary to consider the nature, extent, and impact of changes since the period of significance. Integrity also depends on the area's historic context. A property that retains elements such as field patterns and boundary makers that are not present at other properties in the vicinity may be deemed significant, despite the deterioration and loss of other constituents. Similarly, the loss of a few features usually does not affect the overall integrity of a resource, but the repeated loss of buildings and small-scale features may result in the cumulative loss of integrity. The greatest loss of historic integrity results from new construction, and incompatible land uses covering extensive acreage.

For archaeological sites, the remains of prehistoric or historic-era activities must be in the original location in which they were deposited, and must retain sufficient association either with an historic event or prehistoric activity that they possess data that can address research issues of regional importance.

Assessing Contributing And Noncontributing Resources

Buildings, structures, objects, and sites are classified as contributing or noncontributing based on their historic integrity and association with a period and area of significance. Those resources not present during the historic period, not part of the property's documented significance, or no longer reflecting their historic character are noncontributing.

Prehistoric Archaeological Resources

Prehistoric archaeological resources consist of any material remains of human life or activities (for example, sites, features, or objects) that can provide an understanding of past human behavior (16 U.S.C. Section 470 pp.). Prehistoric sites within the project area could be considered significant and determined eligible for the NRHP if they possess integrity and have a reasonable amount of research potential, that is possess data that have the ability to address the following research issues established for the project:

- Geomorphology and chronology, which in part depend on the site's potential to yield data relevant to regional stratigraphic sequences, absolute dates, or to contribute to relative chronologies by virtue of stratigraphic relationships.
- Paleoenvironmental reconstruction and the ability of resources to contribute evidence directly relevant to reconstructing past environments.
- Environmental change and the presence of information relevant to the study of cultural responses to such change.
- Data contained in ground and flaked stone assemblages and its ability to contribute to our understanding of past techno-environmental and sociocultural systems.
- Information that provides insight into settlement patterns, population density, group size, group structure, and mobility.
- Data that may be used to further an understanding of exchange networks that existed between groups.

- Artifact assemblages associated with specific linguistic groups that may be used to infer migration and population patterns by these groups.

Traditional Cultural Properties

Sites that can yield information about their role in the traditional and cultural activities of living people and their ancestors are potentially eligible for the National Register as Traditional Cultural Properties (TCPs). Their presence in the project area triggers the need for additional Native American consultation prior to the completion of environmental studies and before any mitigation of adverse effect by data collection is undertaken.

Natural Setting

The proposed WPES Project is located in eastern Nevada, a region that is within the physiographic Great Basin as defined by Hunt (1967) and the floristic Great Basin outlined by Cronquist et al. (1972). North-south trending mountain ranges and intervening valleys characterize this portion of the Great Basin. Proposed and alternative power station locations and accompanying substations, access roads, railroad spur lines, and water pipelines and wells are located within Steptoe Valley, which is drained by the north flowing Duck Creek that empties into Goshute Lake. First, Second, and Third Creeks, Fitzhugh Creek, Big Indian Creek, and several smaller unnamed drainages also flow into Steptoe Valley from the Schell Creek Range. Goshute Creek and Cherry Creek form the major drainages from the Egan and Cherry Creek Ranges.

The proposed Thirtymile Substation near Robinson Summit is located at the interface between the Egan Range to the south and Butte Mountains to the north. The area is within the watershed of an unnamed northwest flowing drainage that empties into the northern end of Jakes Valley.

Steptoe Valley is bordered by the Schell Creek Range to the east and the Egan Range to the west. The western flank of the Schell Creek Range, bordering Steptoe Valley, consists primarily of older volcanic rocks comprised of rhyodacite, quartz, andesite, air-fall tuff, and related sedimentary rocks and welded tuff, whereas, the Egan Range is much more complex. The range is primarily composed of layers of shale, limestone, and dolomite with intrusive monzonite and quartz monzonite south and north of Monte Neva Hot Springs. Older volcanics similar to those of the Schell Creek Range also occur north and south of U.S. 50 within and in the vicinity of the proposed substation near Robinson Summit. Monte Neva Hot Springs as well as numerous unnamed springs are located along the west side of Steptoe Valley.

Project areas range in elevation from 5,488 feet above mean sea level (amsl) at the northern end of the project area to approximately 6,200 feet amsl at the southern end of Steptoe Valley. The proposed Thirtymile Substation is situated in the Egan Range on westerly facing slopes with elevations ranging from approximately 6,880 to 7,040 feet.

Varied vegetation can be found within Steptoe Valley. Mid-elevation alluvial fan slopes contain vegetation that is dominated by small sagebrush (*Artemisia arbuscula*). Big sagebrush (*Artemisia tridentata*), Great Basin wild rye (*Leymus cinereus)*, green rabbitbrush (*Chrysothamnus viscidiflorus*), Indian ricegrass (*Achnatherum hymenoides),* and greasewood

(*Sarcobatus vermiculatus)* form the dominant species at the distal end of the fans, with Baltic rush (*Juncus balticus)* located at the bottom of the fans in alkaline soil environments. Near Robinson Summit, within the Pinyon-Juniper woodlands, vegetation is dominated by pinyon pine (*Pinus monophylla*) and Utah juniper (*Juniperus osteosperma*).

Cultural Setting

The WPES project area and its vicinity are known to contain numerous traces of past human activity ranging from early Native American sites and artifacts, to the remains of early trails and transportation routes, historic-era mining, and ranching activities. Such materials can be found at many locations on the landscape and represent the traces of human activities that in some cases extend as far back as 10,000-12,000 years before the present (BP).

Prehistoric Setting

Although earlier archaeological manifestations pre-dating classic Paleo-Indian occupation of the Great Basin may have been identified (James and Zeier, 1982; Lyneis, 1982), such sites are controversial as to their dating and cultural associations, and none have been identified in or near Steptoe Valley. Paleo-Indian (or "Pre-Archaic") sites dating to as early as 11,000 BP are known from eastern Nevada such as those documented at the Ely Airport (BLM Report CRR 8111 [NV 040] 2005-1512), Sunshine Well (Jones et al., 1996) and Giroux Wash (Stoner et al., 2000b). One of the main characteristics distinguishing Paleo Period sites from other prehistoric cultural manifestations is the presence of fluted implements such as Clovis, Folsom, and Plano projectile point forms, crescent shaped implements, choppers, gravers, punches, and an assemblage of steep-edged scrapers, which are primarily unifacial.

Shifting land use patterns, subsistence systems, and the emergence of a wide variety of implement types mark the beginning of the Archaic Period or, in eastern Nevada, the Wendover/Early Archaic Period around 9,500 BP (Aikens and Madsen, 1986; Bryan, 1979; Elston et al., 1979; Jennings, 1986; Jones et al., 1996). Site locations from the earlier years of the Archaic suggest continued adaptations to lake shore environments as those seen in the Paleo Period (Jones et al., 1996; Madsen, 1982, Stoner et al., 2000a) although there appears to have been an increase in the variety of implements and in the types of materials utilized. Projectile point styles consist of Stemmed, Pinto, and Lake Mojave types. However, unlike during the preceding Paleo Period, Archaic peoples seem to have inhabited a much more diverse landscape including not only valley floors and lake margins but cave sites and upland areas as well.

Further shifts in land use, subsistence, and technological systems occurred around 6,000 BP at the beginning of the Black Rock Period, possibly in partial response to a gradual and long-term decrease in yearly rainfall. During this time not only was there an increase in the number of occupation and activity sites scattered across the landscape, but these sites also indicate an increased utilization of upland zones and their associated floral and faunal resources. As during the earlier portion of the Archaic, remains of larger game tend to be found in archaeological contexts. Large side-notched Elko and Gatecliff point forms slowly replace the early Pinto and stemmed point forms.

Near the end of the Black Rock Period, Rose Spring and Eastgate series projectile points appear in archaeological sites (Stoner et al., 2000a), and represent introduction of bow and arrow technology. Other phases from the Middle Archaic, such as the South Fork Phase (Elston, 1986) begin to show evidence of increased populations, more diverse subsistence and technological patterns, and the first evidence of artistic expression in the form of ornaments and rock art (Elston, 1986; Heizer and Baumhoff, 1962; Thomas, 1983; Schaafsman, 1986). Sites tend to be larger and more numerous than in earlier periods. Milling equipment reflects the increased subsistence diversity and exploitation of various seeds such as those derived from the pinyon pine (Fowler, 1968; Thomas, 1983), and may be related to fairly dry conditions (Madsen, 1982).

A shift from the Middle and Late Archaic patterns is seen in the emergence of the Fremont "cultures", Premont/Parowan Period around 1600 BP, described by Marwitt (1986). The appearance of pottery sherds, traces of maize, and a well-developed pinyon gathering and processing technology indicate a dramatic shift from the gathering and hunting economy of the Archaic to a mixed economy including horticulture, providing for sedentary farmsteads and small villages (Marwitt, 1986).

Small villages, ceramics, and some reliance on horticulture characterized the Parowan Fremont culture. Although sharing similarities in design elements and methods of construction with the Anasazi vessels, ceramics of the Fremont differ in the types of temper and vessel form. Near the project area they have been found at the Mariah Site (26LN618) (Brooks et al., 1977) and at Panaca Summit (Elston and Juell, 1987). As rainfall, necessary for agriculture, became more unpredictable the Fremont appear to have abandoned agriculture in favor of a hunting-gathering adaptive strategy in the pinyon-juniper woodlands of western Utah and eastern Nevada, with a terminal date of around 650 BP (Wilde and Soper, 1999).

The arrival of *Newe*, Numic speakers and ancestral Shoshoni, in the area is marked by the presence of brown ware ceramics, twined and coiled basketry, and small side-notched projectile points. While the timing of their arrival and the area from which they moved is widely debated (see Madsen and Rhode, 1994), current evidence suggests that it may be around 1,000 B.P.

Ethnographic Background

Ethnographically, the project area was inhabited by the Western Shoshone. The following provides a brief summary of the ethnographic information. A more detailed overview can be found in James (1981:160-210) and Bengston (2003).

Settlement and Subsistence

The Western Shoshone lived in seasonal semi-nomadic groups that came together during the winter months. Often these camps were located near pinyon caches (Fowler and Liljeblad, 1986). Two ethnographic village locales appear to be located near Ely, on Duck Creek about 8 miles northwest of McGill, at Warm Springs (possible Monte Neva Hot Springs) along the west side of Steptoe Valley, Schellbourne, Egan Canyon, and at Cherry Creek (Bengston, 2003; Steward, 1938:121 and Figure 9).

Because of the presence of diverse ecological zones, subsistence involved the exploitation of various faunal and plant resources. Information on subsistence activities within Steptoe Valley primarily comes from Ely, where pine nuts were gathered in the Egan Range and across the valley in the Schell Creek Range, where they were cached for the winter. Rabbit drives were held immediately following the pine nut harvest (Steward, 1938:123).

A consultant of Steward indicated that prior to the arrival of Europeans, horticulture was introduced by peoples from the south. While limited in production it involved the propagation of corn, large blue pumpkins, and large white beans (Steward, 1938:122). The people of Egan Canyon, a natural travelway between Steptoe Valley and Butte Valley, were linked with peoples in both regions (Steward, 1938:146), and apparently obtained subsistence resources from both regions. For antelope drives they traveled west to Butte Valley or south to Steptoe Valley (1938:147). Those from Ely went to Spring Valley near Cleveland for antelope drives and to Spring Valley and Snake Valley for rabbit drives, and also to northern Steptoe Valley near Cherry Creek (1938:122). Festivals involving dancing and gambling were conducted after the pine nut harvest, and involved local affairs followed by larger events held on Duck Creek in Steptoe Valley, at Ely, Cherry Creek, Cleveland, Baker, and White River Valley (1938:122-123).

Political Organization

Western Shoshone families usually belonged to small, local geographic districts within the general expanse of Western Shoshone territory and were usually centered within a single valley or cluster of winter villages. These units tended to be stable, within areas with predictable resource availability, but were subject to change in more marginal environments. This organization led Steward to conclude that the political organization was a direct function of social and economic conditions (Steward, 1937), with regional groups named after prominent resources. For example, the people of Steptoe Valley were referred to as *Pa'anaihteen*, or "The people from up above" (Steward, 1938:121). Fowler indicated that such labels were not socio-political, but that the primary significance was as a signal to outsiders that people living in the 'rye-grass eater' area had that commodity to share. Therefore, it served as more of an economic function. (Fowler, 1980 in James, 1981:200). Headmen were generally restricted to periods of communal activity (Thomas et al., 1986:276).

Individual property was owned, however resources were considered to be communal property and ownership did not transfer to the individual until the resource was transformed into something of use. For example, sources of basketry material were not owned, but once harvested and formed into a basket the basket was then owned by the individual.

Ideology

Other than a belief in animism as it relates to nature and the sun, no formal system of supernatural beliefs existed. Most important were the presence of power, a major part of Shamanism, and the art of healing (James, 1981:205). Shamen had the ability to cure specific ailments, use their powers for their own benefit, or had general curing abilities (Steward, 1941:257).

Round dances generally held throughout the Great Basin in the past or presently include the two (1869 and 1889) Ghost Dances, the Bear Dance, and the Sun Dance, the latter of which is important to the Western Shoshone. The dance originated in the Plains, around 1700, spreading to the Plateau region and then to the Wind River Shoshone around 1800, and from there to the Western Shoshone in Nevada (Shimkin, 1953:472). While varying from the Plains event, similarities were fasting by the dancers with the general objective being the promotion of health and the public good. Unlike the original, the dance also promoted the healing process (Shimkin, 1953; Jorgenson, 1986).

Ceremonial and Historic Sites

Several areas within the vicinity of the proposed project were known to have ceremonial significance. Hot springs north of Ely (possibly referring to Monte Neva Hot Springs, among others) were used for ritual purposes (Facilitators, 1980:3.19 in Bengston, 2003:119). Steptoe Mountain, the location of which is unknown, is associated with the Shoshone story about *Watoavic*, also referred to as *Si-ets*, a man made of stone who killed a number of Western Shoshone children (A. Smith, 1993:165 in Bengston, 2003:98). Two areas are of historic significance based upon events that occurred in the past. Both are known as massacre sites where the U.S. Cavalry destroyed villages located east and north of Ely in the 1860s. The exact locations of these villages, however, are not presently known (Facilitators, 1980:3.18 and 3.19 in Bengston, 2003:106).

Historic Background and Setting

Marking the beginnings of the historic era in the White Pine County region is largely based on rather arbitrary temporal and cultural markers. Although contact between European and American traders and trappers and the ethnographic Shoshone had likely been taking place since the early decades of the 19th century at the very least, sustained contact between Native and Euro-American populations did not occur until the 1850s and 1860s (Bailey, 1966; James, 1981; Patterson et al., 1969). One of the first expeditions was in 1853, and was organized by Lieutenant Colonel E. J. Steptoe, who sent a detachment into Nevada led by John Reese to search for a possible route for the troops that were wintering in Salt Lake City (Patterson et al., 1969:86-87; Morgan, 1943:224-227 in Vlasich, 1981:216). During the winter of 1859 another expedition was led by Captain James H. Simpson. A part of this mission Howard Egan, a Mormon scout, explored possible routes for Chorpenning's California Mail Company (Morgan, 1943:233; and Mordy and McCaughey, 1968:226 in Vlasich, 1981:216). During this time, the influence of the U.S. Government in particular became increasingly felt among the Shoshone and within a short period of time in the 1850s, their traditional lifeways and subsistence patterns were largely ended. Informal settlements had been established near American ranches, mines, and other areas of economic and industrial activity (Malouf and Findlay, 1986).

As the population of Euro-American settlers and entrepreneurs increased in the White Pine County region, particularly following the Ruby Valley Treaty, several predominant economic patterns and general themes of historical development emerged during the middle of the 19th century. Those themes of particular relevance to the White Pine County area include mining, ranching and agriculture, and transportation and communication.

Mining

The economic and social development of eastern Nevada during the 19th century is more associated with the emergence of the mining industry than any other economic activity. In fact, the existence of Nevada as an independent state is due primarily to the wealth of the Comstock Lode, which helped convince the U.S. Congress and President Lincoln to create this new territory from the western section of Utah in 1861. Desperately needing additional sources of revenue for the Union cause during the Civil War, Lincoln saw to it that Nevada was declared a U.S. state in 1864 (Hulse, 1972). Following the Civil War and throughout the latter decades of the 19th century, mining continued to be the single most important economic endeavor throughout the state, although the boom and bust cycles intrinsic to the industry kept the population of much of Nevada at a very low level until the early 20th century.

Mining in White Pine County, was organized into districts in 1869. Mining began as early as 1859 with the discovery of silver ore on the south side of Pleasant Valley in what became known as the Eagle District, but was also known as the Pleasant Valley, Kern, Regan, Red Hills, and Tungstonia Districts (Smith, 1976:82). The mineral wealth of this district included silver, gold, and copper; some of the early claims went to employees of the Overland Mail Company who apparently found some deposits during the course of their duties on the Pony Express route (White, 1871:81 in Smith, 1976:82; Lincoln, 1923; Hill, 1916). Other early mining districts in the county included the Cherry Creek District (also known as Gold Canyon and Egan Canyon District); operations were supported by a 20-stamp mill located near the Egan Canyon Pony Express Station (Hill, 1916; Schrader, 1931; Smith, 1976).

While districts such as Cherry Creek and Gold Canyon (combined with Cherry Creek in 1872) were the scenes of extensive and initially exciting activity, they quickly faded. Lesser known and far less profitable mining districts closer to the proposed WPES Project are the Nevada District in the western foothills of the Schell Creek Range, near the southern end of Steptoe Valley; the Granite (Steptoe) District covering the east slope of the Egan Range from Water Canyon south to Septoe; the Duck Creek District, which includes all of the Duck Creek Range and the south end of the west slope of the Schell Creek Range; the Cleve Creek District in the central part of the Schell Creek Range; the Taylor District on the west slope of the Schell Creek Range from the Summit to Steptoe Valley; and the Telegraph District, which includes both slopes of the Egan Range and all of Telegraph Canyon, which was named for the first transcontinental telegraph line (Smith, 1976:36-50). Of indirect importance to the project was the Robinson District, west of Ely, which is discussed in greater detail below. Mining continues today throughout the region and while it is still an important contributor to the financial and social well being of the area, it no longer constitutes the economic foundation of White Pine and surrounding counties.

Ranching and Agriculture

The mineral strikes in Nevada after 1859 were the impetus for significant agricultural and livestock development in the state. As mining flourished, it required support systems to feed its burgeoning population. As the mining activity lulled, or rich areas were depleted, ranching and agriculture continued for those desiring to settle in the area (James, 1981).

The earliest known organized farming in Nevada occurred when John Reese and his party from Salt Lake City arrived in the Carson Valley in June of 1851 and planted barley, corn, turnips, and watermelons, which they sold to emigrants on the way to California (Elliott, 1987). However, the first cattle to enter the region accompanied the Joseph Walker party on his return trip to Salt Lake in 1834 (Elliott, 1987). Subsequent emigrant parties brought livestock through Nevada as well, and often sold exhausted animals to settlers along the way (James, 1981).

Although irrigated agriculture was in its infancy around this time, the demand for fresh fruits and vegetables induced some farmers to plant row crows and orchards. In the Steptoe, Spring, and Snake Valleys of White Pine County, earthen ditches were used to divert water from streams and springs, making irrigated agriculture possible. With only one percent of its land being irrigated by the late 19th century, however, Nevada was not generally known for its produce, but rather for its grazing land and stock feed (True, 1913; Elliott, 1987, Southern Pacific, undated).

Similar to mining, cattle grazing in White Pine County has also followed boom and bust cycles. In 1874, the first full year branding and registration of cattle was required, over 100,000 head were recorded in this region; by the early 1880s, as mining activities began to "bust", just over 32,000 head were registered. These numbers fluctuated considerably, but by 1902 mining activities once again increased and so did the cattle, with 150,000 being registered in the area (James, 1981). Those numbers would decrease over the next few years. The demand for agricultural products, in general, would fluctuate statewide throughout the 1910s, however demand was again revitalized during the course of World War I (Elliott, 1987; James, 1981).

Agricultural activity was more or less stable throughout the ensuing decade, but underwent economic hardship during the Depression of the 1930s. With various ranches and farms statewide requiring federal aid, farmers and stockmen suffered extreme hardship from 1930 until the start of World War II (Elliott, 1987).

Nevada agricultural production since the late 1940s has generally increased in spite of occasional setbacks. Livestock have continued to make up the largest share of total agricultural output. Sheep production has never completely recovered from the decline of the 1930s. Before the Depression, there were over one million sheep in Nevada. During the 1930s, that number decreased to half that amount. By the 1980s, sheep numbered a little more than 100,000 throughout Nevada (James, 1981; Elliott, 1987).

Early Transportation and Communication

As with virtually every other economic endeavor in Nevada, industries dealing with transportation and communication activities were established, at least initially, in reaction to the booming mining industry in the mid-1800s. Emigrant and shipping routes were established early on for settlers and California-bound gold miners but in large part these were intended only to provide passage through the state, not bring settlers to stay. Again, as the mines boomed, Nevada became just as much a destination as it was a hindrance to western travel.

As mentioned previously, beginning in 1855 Major Howard Egan of the Mormon Battalion first traversed and three years later surveyed a route through central Nevada for Major George

Chorpenning. In 1859, Capt. James Simpson led an expedition through the region resulting in the establishment of the first route through central Nevada, from Camp Floyd, Utah to Genoa, Nevada (Vlasich, 1981:228; Welch, 1979:6 in Bowers and Muessig, 1982:19). Although this route, originally known as the Egan-Simpson or Central route, proved unsuitable for a railroad, the route was suited to wagon traffic, and was quickly adopted by George Chorpenning's mail line, which used mules. Informally known as the "Jack-ass Mail" the operation was first established along the Humboldt River (Goetzmann, 1966:293 in Bowers and Muessig, 1982). By December of 1859, George Chorpenning had built several stations along the new route (Godfrey, 1994), and one of these was located at Schellbourne (Townley, 1986:53). At the same time, Russel, Majors and Waddell, owners of the Central Overland California & Pikes Peak Express Company (COC & PP Express Co.), had been actively soliciting Congress for the establishment of a 10-day mail service by Pony Express from Sacramento to St. Joseph, Missouri, while at the same time laying out and establishing stations along the same route used by Chorpenning (Townley, 1986:7-8; Godfrey, 1994). In the wake of cash flow problems, Chorpenning's mail contract was terminated in May of 1860, and was promptly awarded to the COC & PP Express Co. Russel, Majors, and Waddell hoped by demonstrating "that the central route offered the best opportunity for mail or stage…the firm could inherit the (proposed route of the) Pacific railroad" (Townley, 1986:8). Between Salt Lake City and Placerville, California, Chorpennings's posts were taken over by the COC & PP Express Co., and others were added with whatever building material was available—rock, timber, adobe, or sod (Townley, 1986:8). This new subsidiary venture, more commonly known as the Pony Express Mail Service began in April of 1860. Within and in the vicinity of the proposed WPES Project a route remount station was established in the spring of 1860 at Egan Canyon and Chorpenning's station at Schellbourne (called the Schell Station by early residents) was enlarged (Townley, 1986:52-53). The route is currently overlain by a gravel road extending west from U.S. 93 at Schellbourne and is bisected by the proposed water supply pipeline ROW.

Operations of the Pony Express enterprise were not without problems, the first of which arose shortly after the system was put in place. Following, and apparently as a result of the Pyramid Indian War, raids by local Native American groups on Pony Express stations and riders occurred throughout Nevada and Utah. At the Egan Canyon station, a natural area for an ambush and a point where one of Chorpenning's riders was attacked in March of 1859, the Pony Express and local Native peoples came into conflict several times. Cavalrymen killed almost twenty Shoshone warriors in July of 1860, and in October the Shoshone stormed the station killing the two station tenders. Similar hostilities occurred at Schellbourne where the station was destroyed in June of 1860, supposedly by the same group that had attacked the Egan Canyon station. These disruptions in service were not only costly because of the loss of revenue, but required that the stations be rebuilt as small fortresses. Additional blows to the operation occurred during the winter of 1861, when deep snows resulted in numerous delays. This disruption in service coupled with the overwhelming debt and criminal charges against William Russell for stealing bonds from the Interior Department to support and maintain the Pony Express, and completion of the Overland Telegraph line on October 24, 1861, finally resulted in the failure of the enterprise (Godfrey, 1994). Although short-lived, 1860-61, the Pony Express demonstrated the importance of a Central route, which became even more important following the seizure of Butterfield's southern route by the Confederate army in January of 1861 (Townley, 1986:13).

Following the collapse of the Pony Express, competition for government contracts for the transportation of mail and passengers over the Central route ensued between the COC & PP Express Co. and Butterfield's Overland Mail Company. As a compromise, Congress awarded the COC & PP Express Co. the eastern portion of the route from the Missouri River to Salt Lake City. There, post and passengers were transferred to the Overland Mail Company, which completed the first run to San Francisco on July 18, 1861 (Hafen, 1926:165ff; Townley, 1986:13).

A map of the Overland Stage and Pony Express routes across Nevada (Townley, 1986:10-11) indicates that the Overland Stage followed the same route as the Pony Express had through Steptoe Valley. When the Overland Stage began daily service they established Schellbourne as the district headquarters, with stonemasons from Utah constructing a headquarters building, wagon shops, and stock barns between 1862 and 1863. Townley (1986:54) notes:

> A crew of twenty blacksmiths, wheelwrights and workmen operated shops capable for rebuilding stages from the ground up. Storage yards kept the division's replacement equipment and winter supply of "mud wagons" ready for use. A paint shop could replace the gleaming exterior of the line's Concord coaches. Harness was repaired by experienced leather craftsmen and stored in elaborate warehouses. A five-acre garden kept the staff in vegetables and a farm crew harvested thousands of tons of hay, plus wagonloads of grain annually.

As the transcontinental railroad neared completion, overland mail and coach service retreated, and even the Overland Telegraph was re-routed along the railroad, following the joining of the Central Pacific and Union Pacific in May of 1869.

With the completion of the Transcontinental Railroad and the coming of the Central Pacific to the north of White Pine County, overland transportation took a dramatic turn. The largely isolated nature of eastern Nevada was rapidly coming to an end and new markets for the industrial and agricultural/ranch produce of the region soon emerged. Although the Central Pacific was situated well to the north of White Pine County, at first wagon roads and then the Nevada Northern Railway in late September of 1906 linked Ely to this route and provided easy transportation to other population centers such as Cherry Creek Station, Currie, and Elko (James, 1981; Myrick, 1992). Additional rail lines and spurs were established extending the route east to Copper Flat and another spur to McGill. Throughout the majority of its existence the line primarily carried copper ore to the processing plants at McGill. Roadways began to proliferate and improved conveyance of goods, services, and people across the landscape. Mack and Sawyer (1965) provide an excellent illustration of these developments in their study, which demonstrates a rapid increase not only in rail lines but in roadways and in the establishment of population centers in eastern Nevada between 1865 and 1910).

Nevada Northern Railroad

As with many short-line railroads in Nevada, their formation was the result of mining, and in this case provided a means for the movement of blister copper from the rich deposits of the Robinson Mining District west of Ely. Early mining in the vicinity of Ely began in 1867 with the gold discoveries by Thomas Robinson, whose name the district is now known. The name Ely was the result of Frederick Thomas of Oakland, California, who named the emerging

town of Ely after Smith Ely, a Vermont smelter operator and then president of Selby Copper Mining & Smelting Co. However, it was copper that made Ely famous and it all started with Mark Requa who was looking for additional business for the struggling Eureka &Palisade Railroad out of Eureka. He sent J.B. Stevens to look for new mineral deposits to the east of Eureka, who reported the extensive porphyry copper ore deposits in Copper Flat, just east of Ely. Subsequently Requa purchased the Star Pointer and Ruth Mines in 1902, and combined these into the White Pine Copper Company in 1903. With new technology it became apparent that the crystalline form of copper could be mined economically, and Requa looked for a method of shipping the commodity to market. While the Eureka & Palisade Railroad was only 75 miles to the west, it presented two obstacles. First, it was of narrow-gauge construction, which at the time was inferior to the wider standard gauge. Second, to construct a route from Eureka would mean traversing four mountain passes. It seemed logical that the most cost-effective route was north through Steptoe Valley, via a nearly flat route with easy grades to a connection with the Central Pacific at or near Wells (Myrick, 1992:13-114).

William Hood, a Southern Pacific engineer, was selected to lead the construction of the route. He obtained the expertise of Adolph Judell, who had just finished working on a Southern Pacific route north of Chico, California, to survey the route. Judell selected a route down the center of Steptoe valley, which was supported by Hood among disapproval from others who believed that a route higher upslope would be preferable. Judell defended his selection by pointing out that an upslope route would be subject to intense channeled runoff from the higher elevations, whereas a route through the lowlands would be in an area where the flow would be spread out and less intense (Myrick, 1992:114).

With an influx of capital from W. Hickle Smith, a member of the Bullfrog Mining Syndicate, and approval from Southern Pacific for a connection the Nevada Northern Railway (NNR) was formally incorporated in June of 1905, and became part of the Nevada Consolidated Copper Company (NCCCo). Delayed by the severe winter of 1905-1906 the route south from Cobre (Spanish for Copper) reached Currie in the spring, Cherry Creek Station in July, and was completed to Ely in late September of 1906.

The route was extended 10 miles east into Copper Canyon and the copper mines west of Ely, which required the construction of two tunnels. It is said these 10 miles cost as much to construct as the entire 140 miles from Cobre to Ely. Other additions included a route to McGill, which was used to transport high school students to Ely, and a nine-mile Hiline built in 1907 to bring ore to the concentrator upslope of McGill.

While the processing and transporting of copper ore by far made up the bulk of the business of the tonnage shipped by the company, passenger service and commercial freight also contributed to its economic success in the early years of operation. However, with improved highways, public use declined and passenger service was suspended in July of 1941.

Before the route to the mines and McGill could be completed, the Guggenheim interests purchased sufficient stock to obtain working control of the NCCCo. S. W. Eccles became the new president of both organizations and with the infusion of additional capital the smelter planned for McGill was doubled in size. In 1932, Kennecott Copper gained control of NCCCo, forming the Nevada Consolidated Copper Corporation to run properties in Nevada, Arizona, and New Mexico. Late in 1942 the Nevada properties were reorganized under the name of the Nevada Mines Division of Kennecott Copper Corporation. With declines in the

economies of scale brought about by declining copper prices, Kennecott donated the East Ely depot and yards, the McGill depot, and 32 miles of track to the City of Ely, which formed the White Pine County Historical Railroad Foundation. The depot and rail yards are currently listed on the NRHP and the foundation is in the process of listing these facilities as a National Historic Landmark (Myrick, 1992:133-134). However, the significance of the NNR is not just related to its infrastructure, but the connection with the Robinson Mining District and the part it played in the early development of the district that has been referred to as the richest mining district in Nevada History (Elliott, 1987:226).

Another use of the NNR was in 1908, when this appears to have been the route of the Great Race. The event was sponsored by the New York Times and featured an automobile race from New York City to Paris. According to Southwell (2006), the route went south through Steptoe Valley following the NNR, through Ely, and then on to Tonopah.

Highway Development and the Lincoln Highway

As the 20th century progressed, railroads remained the primary means of moving people and goods within and through Nevada, but the automobile was fast becoming a major player on the transportation scene. Tasker L. Oddie, who became Nevada governor in 1911, could see the developing importance of the automobile and one of his first official acts was to authorize the State Engineer to utilize convicts for road construction. Although this plan eventually failed, it established the concept and priority of building modern roads throughout the state. However, by 1914, only 262 miles of Nevada's 12,812 miles of existing roadway were paved and Nevada had a long way to go to provide for the automobile.

An exception was the establishment of the Lincoln Highway in 1913, which was one of America's first transcontinental automobile routes, beginning in Times Square in New York City and ending at the Palace of Legion of Honor in San Francisco. This was the vision of Carl Fisher, the founder of the Presto-O-Lite Company that made headlights for automobiles. He, along with help from Henry Joy of Packard Motor Car Company and Frank Sieberling of Goodyear Tire and Rubber Company formed the Lincoln Highway Association in 1913. At first the route was called the "Coast to Coast Rock Highway" but following input from Henry Joy, the name was changed to the Lincoln Highway in honor of President Abraham Lincoln. However, the motives varied among the founders. They included the desire to build an appropriate memorial to the fallen President, as well as the desire to grow their automotive businesses (National Park Service, 2004).

Americans viewed the emergence of the Lincoln Highway, and the automobile as a manifestation of a modern equivalent of the Oregon Trail or as an equivalent of freedom from travel via the Transcontinental Railroad. The highway and automobile freed the populous to travel and enjoy the spectacles and all of their glamour thorough the entire United States without constraints. In 1913 Carl Fisher led a group of 19 automobiles from Indianapolis to reconnoiter a route to the Pacific Coast. He insisted that the route taken would not necessarily be the one chosen for the Lincoln Highway, but state and local governments worked to improve routes just in case. For example, Nevada spent $25,000 in road improvements and several events were held at each stop where the entourage was wined and dined by high-ranking political figures, including the governor of Nevada (National Park Service, 2004).

Several important events occurred during the early years of the highway. They included the first Army Transcontinental Motor Convoy in the summer of 1919 and the official marking of the route in 1928, when Boy Scout troops placed 3,000 concrete markers bearing the Lincoln Highway logo (an "L" in a rectangular graphic emblazoned in red, white, and blue), a bronze medallion of President Lincoln, and a blue directional arrow along the length of the highway (National Park Service, 2004).

While politics played a role in the final selection of the route, it primarily was determined by geography. Although not the only transcontinental route in the early 20th century, it was the best known. The modern route of Interstate 80, the route of the immigrant trail that follows the Humboldt River, is a far superior route compared to the central Nevada route, which crosses several mountain passes exceeding 7,000 feet elevation. However, in Utah the early route of the Lincoln Highway was primarily determined by the geography. The Great Salt Lake Desert blocked the way west from Salt Lake City, until limited funds were available for construction of a raised roadway across the barren salt flats. Because of this, the early route went around the south end of the desert to Ely. However, the popularity of this route began to decline after 1919 when the State of Utah abandoned their commitment to complete the Lincoln Highway's Goodyear Cutoff at the southern tip of the Great Salt Lake Desert in favor of a 40 mile long route to Wendover, which became known as part of the Victory Highway.

The Lincoln Highway Association formerly abandoned the Ely route for the Wendover route with the stipulation that Nevada build an 80-mile route south from Wendover linking the new and old routes. The final blow to the route through White Pine County was in 1927 when the Lincoln Highway Association abandoned the route through Ely for the Wendover route. As a result, Nevada built an 80-mile route south to link up with the Lincoln Highway south of County Road 18 north of Ely. By the time the route was completed in 1930, the more direct Victory Highway (U.S. 40) along the Humboldt River Valley had been improved sufficiently to capture most of the traffic traveling across the Great Basin.

Additional alterations to the route were made in the 1920s. Large portions of the route between Ely and Eureka were completely relocated northward during the early 1920s and are currently followed by U.S. 50. Another change in the route is just west of Schellbourne Pass, where there is a split in the road, with the early 1913 route descending to Schellbourne Ranch, and the right (north) branch being an upgraded route established in 1919 (Franzwa, 2004:8). However, except for the route to Wendover, which was completed in 1930, the route through Steptoe Valley has remained in its original alignment established in 1913.

One original rest stop, Magnuson Ranch, remains in Steptoe Valley. The house that served as a rest stop beginning in 1913 is still standing, but is no longer occupied. The 1915 Road Guide describes the ranch as a place to obtain "Meals, lodging, gas, oil, drinking water, radiator water, camp site." In 1924 "telephone" had been added to the guidebook (Franzwa, 2004:8)

By the mid-1920s the named routes overlapped and were poorly routed. Therefore, in 1925 and 1926 the American Association of State Highway Officials and the U.S. Bureau of Public Roads under took the task of identifying and marking the various east-west transcontinental routes into a grid of nine major routes numbered U.S. 2, 20, 30, 40, 50, 60, 70, 80, and 90. The Lincoln Highway was designated U.S. 30 for most of its length. However, it retained its popular identity as the Lincoln Highway until 1956 with the passage of the Federal Aid Highway Act and development of the modern interstate system.

Appendix Q

Documentation of the Application of Numerical Model to Simulate Ground Water Response to Pumping for the Proposed White Pine Energy Station in Steptoe Valley, Nevada

APPENDIX Q
TECHNICAL MEMORANDUM **CH2MHILL**

Documentation of the Application of a Numerical Model to Simulate Ground Water Response to Pumping for the Proposed White Pine Energy Station in Steptoe Valley, Nevada

PREPARED FOR: White Pine Energy Station EIS Project File

PREPARED BY: CH2M HILL

DATE: September 13, 2006

Introduction

Ground water from the basin-fill deposits in Steptoe Valley is proposed as the source of water for the White Pine Energy Station (WPES), a proposed up to 1,600-megawatt coal-fired electrical generating station to be located in Steptoe Valley, White Pine County, Nevada. The maximum annual water demand for the WPES is approximately 5,000 acre-feet (af). For the purpose of the analyses in this technical memorandum, the maximum project life with respect to this water demand is 40 years. This demand would be met through pumping from a wellfield composed of 8 wells, which are not yet constructed. The principal features of the proposed project, including the locations of each well in the wellfield, are shown in Figure 1 for the Proposed Action and in Figure 2 for Alternative 1.

The principal objective of this technical memorandum is to document the use of a numerical ground water flow model to simulate the response of the Steptoe Valley basin-fill aquifer system to ground water pumping required to meet the project demand for water, up to 5,000 acre-feet per year for 40 years. Although this demand for water would be the same for either the Proposed Action or Alternative 1, the demand would be met through the operation of two different wellfields, each consisting of eight water supply wells in a linear configuration on the valley floor roughly parallel to U.S. 93. Specifically, for the Proposed Action, the eight wells in the proposed wellfield would be located at intervals of between approximately 1 and 3 miles extending from the proposed energy station location northward for approximately 12 miles. The eight wells in the proposed wellfield for Alternative 1 would be located at intervals of between approximately 1 and 2.5 miles extending from the Alternative 1 energy station location south for approximately 5 miles.

This technical memorandum has been prepared to support the environmental documentation for the proposed WPES, which is being developed by White Pine Energy Associates, LLC, a wholly owned subsidiary of LS Power Development, LLC.

Ground Water Flow Model

Inasmuch as multiple wells would be required to meet the project water demand, a numerical ground water flow model was determined to be the most appropriate tool to determine a reasonable range of potential ground water level declines in the Steptoe Valley that could be anticipated to occur as a result of project specific ground water withdrawals in support of either the proposed action or the alterative energy station location.

In determining a reasonable range of anticipated decline in ground water levels, the principal objective is to gain an understanding the difference in ground water levels between non-project pumping and project pumping. A complete understanding of the current water levels is therefore not required; only the change in water level brought about by project pumping is important.

Accordingly, the simulation of potential project-induced ground water level decline was conducted using a revised version of a numerical model previously developed, in part, to examine the potential consequences of pumping from the same well locations as proposed for the WPES. Specifically, the model developed by Frick (1985) was re-created using grid dimensions and estimates for model input parameter values that matched as closely as possible the ones used previously by Frick. In addition, the model in Frick (1985) was revised to simulate transient conditions. The original model solved only for steady-state hydraulic heads.

Although the Frick model was calibrated to conditions in the mid-1980s, it was determined to be an appropriate tool to address the fundamental issue of potential project-induced ground water level declines (i.e., it sufficiently represents the ground water conditions in the basin-fill aquifer system in the Steptoe Valley to be able to provide reasonable approximations of the change in ground water levels that would occur as a result of project pumping). Frick (1985) acknowledges that although the model was considered calibrated, there were (and are in 2006) insufficient data to verify that the model can reproduce a historical hydrogeologic condition that is independent of or different from the conditions reproduced during calibration. Nevertheless, the calibrated model was still considered to be a valuable tool to test hypotheses about the basin-fill ground water system and its response to different stresses (Frick, 1985).The model developed by Frick (1985), and the one subsequently used for these analyses, is based on the three-dimensional finite difference ground water flow model commonly referred to as MODFLOW, which was first developed by McDonald and Harbaugh (1984) and subsequently formally documented in McDonald and Harbaugh (1988). Since initially published, MODFLOW has been updated to run on personal computers using Windows®-based platforms, and to simulate more complex ground water environments and boundary conditions with more efficient matrix solver routines. In re-creating Frick's model, the MODFLOW 96 version in Ground Water Vistas® 4.20 (GWV) was used. This version essentially uses the same basic computer code as originally published and, therefore, used in Frick (1985).

Principal Assumptions

The following assumptions provide important context for the model setup and subsequent simulation results:

- Fundamentally, the most important assumption is that the conceptual model of the Steptoe Valley basin-fill aquifer system developed by Frick (1985) is sufficiently accurate, and that the subsequent representation of the conceptual model by the MODFLOW-based model is also reasonable for the purpose of meeting the objectives of the simulations for the WPES environmental documentation. Accordingly, the lateral and vertical extent of the simulated problem domain, the finite-difference grid dimensions, the values for fundamental model input parameters, and the initial and boundary conditions for the re-created model are as close as possible to those employed by Frick (1985).

- Actual operating conditions for the project wellfield have not yet been determined. Therefore, each project well was pumped at the same rate (5,000 af/year ÷ 8 wells = 387 gallons per minute [gpm]) continuously for 40 years).

- In Frick (1985), background (non-project) ground water withdrawals were held constant at 20,289 af/year, and this rate was apportioned to different finite-difference cells based on known local pumping centers as of 1985. For the re-created model, background ground water pumping was held constant at the combined estimated rate as of 2000 (6,360 af/year), which is the last year for which published estimates of ground water withdrawals in Steptoe Valley are available (Lopes and Evetts, 2004). However, the current spatial distribution of pumping in Steptoe Valley is unknown; consequently, the same pumping areas identified in Frick (1985) were used in the re-created model, but with the pumping rate of 6,360 af/year evenly distributed across the same finite-difference cells identified as pumping cells in Frick (1985).

- The model developed by Frick (1985) only solved for steady-state hydraulic heads. Accordingly, storage properties of the aquifer system were neither quantified nor accounted for in the model input data in Frick (1985)[1]. However, to simulate ground water level declines after 40 years of project pumping, transient head solutions are required. Inasmuch as the solution to the partial differential equation for anisotropic time-dependent ground water flow requires that storage properties be known or assumed, appropriate values of both specific yield (Sy) and storage coefficient (S) are required for model layers representing unconfined and confined conditions, respectively. For the re-created model, it was assumed that the values of Sy and S would be constant in space. Specifically, the value of S applied to model Layers 2 and 3 representing confined conditions (see Model Setup section below) was 1 x 10^{-4} following sensitivity testing that revealed essentially no difference between results with S = 10^{-3} and S = 10^{-5}. A value of

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[1] Under steady-state conditions, the right-hand side of the partial differential equation for ground water flow:

$$\frac{\partial}{\partial x}\left(K_x\frac{\partial h}{\partial x}\right)+\frac{\partial}{\partial y}\left(K_y\frac{\partial h}{\partial y}\right)+\frac{\partial}{\partial z}\left(K_z\frac{\partial h}{\partial z}\right)+W=S_s\frac{\partial h}{\partial t}$$

goes to zero because $\frac{\partial h}{\partial t}=0$; therefore, under steady-state conditions, aquifer storage properties (specific storage [Ss]) are irrelevant. For the definitions of the other terms in this equation see, for example, Freeze and Cherry (1979).

$S = 10^{-4}$ is consistent with the results of aquifer testing in Steptoe Valley reported in Leeds, Hill, and Jewett (1983). However, simulation results were sensitive to changes in the value of Sy assigned to Layer 1. For example, a value of Sy = 0.05 ultimately resulted in drawdowns in response to project pumping of between 1 and 10 feet higher than when Sy = 0.25. The greatest differences in drawdowns resulting from the different values of Sy were closest to the pumping centers while the smallest differences were at the margins of the cone of depression for the wellfield[2]. A value of Sy = 0.05 was used in the final simulations because it was the lowest reasonable value that was consistent with the documented near-surface lithology (see, for example, Clark and Riddell, 1920; Leeds, Hill, and Jewett, 1983). Selecting the lowest of the range of reasonable values of Sy maximizes the resulting simulated wellfield drawdowns in Layer 1.

Model Setup

Problem Domain and Model Grid

The simulated problem domain and the associated finite-difference grid are shown in Figure 3 relative to the location of the proposed wellfield under the Proposed Action, and in Figure 4 relative to the location of the proposed wellfield under Alternative 1. The problem domain and lateral (x-y) dimensions of the model grid are the same for both the Proposed Action and Alternative 1, and are the same as employed in Frick (1985) with the grid spacing of Δx = 5,280 feet (1 mile) and Δy = 10,560 feet (2 miles). The x-offset of the grid in GWV was 2215399.51, and the y-offset was 14118722.49 (NAD27, UTM 11N). These offsets placed the bottom left (southwest) corner of the finite difference grid as close to actual coordinates as possible.

In the vertical dimension, the problem domain was discretized into three layers following the approach in Frick (1985). The upper-most layer (Layer 1) represents the upper 100 feet of saturated thickness, and is assumed to be unconfined (LAYCON=1). Layer 2 represents the principal confined aquifer unit (LAYCON=0) and extends from the bottom of Layer 1 to approximately 1,000 feet below land surface at the lowest point along the east-west width of the valley. Layer 3, which is also confined, is below Layer 2 and represents deep ground water which, while not tapped directly by wells, influences the hydraulic response to pumping from Layer 2 (imposing a no-flow boundary at the base of Layer 2 would be inappropriate because it would limit the water available to deep wells).

The elevation and thickness (layer tops and bottoms) were created by approximating layer thickness directly from Figure 15a and 15b in Frick (1985). Specifically, the lowest point on Figure 15b was selected as the base elevation datum in the model (zero elevation). All other layer elevations in the model are a particular value above the datum based on the approximated thickness from Figure 15b in Frick (1985). While every effort was made to duplicate the layering discretization in the previous model, this portion of the model setup was not very well documented in Frick (1985). The resulting inherent differences in the vertical discretization between the two models ultimately led to the greatest differences in the solutions produced by the two models.

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2 Sensitivity testing indicated that at the margins of the cone of depression for the wellfield there was no significant difference in the results between Sy = 0.05 and Sy = 0.1.

Hydraulic connection between the layers is simulated through confining layers that are not specifically represented spatially by the model but are approximated through leakance parameters (these confining layers only transmit water in the vertical direction and are not capable of storing water).

Model Input Parameters

The values of the basic model input parameters (hydraulic conductivity, leakance, recharge, evapotranspiration) including grid specifics were taken from Frick (1985), and are presented spatially in Figure 5 through Figure 14.

Boundary Conditions

Boundary conditions for MODFLOW are: no-flow finite-difference cells (deactivated cells outside the model domain); ground water pumping cells (both non-project and project wells); stream cells representing Duck Creek and Steptoe Creek; and general head boundary (GHB) condition cells.

The GHB package in MODFLOW was used to represent ground water flow north from Steptoe Valley into Goshute Valley in the vicinity of Currie. The GHB cells are identified in Table 1.

TABLE 1
General Head Boundary Condition Location and Properties

Layer	Row	Column	Head Elevation (feet)	Width (feet)	Distance to GHB head (feet)	Hydraulic Conductivity (feet/day)	Saturated Thickness (feet)	Resulting Conductance ($feet^2/day$)
1	2	15	2,010	5,280	1,000	32.73	10	$1.72x10^3$
2	2	15	2,010	5,280	1,000	49.09	10	$2.59x10^3$
3	2	15	2,010	5,280	1,000	49.09	10	$2.59x10^3$

The stream package was applied to 61 cells in the model according to the routing detailed on Figure 22 in Frick (1985). The revised model employed the "compute stream stages" option available in GWV, based on the flux into the first stream segments (Row 42, Column 13, for Steptoe Creek and Row 31, Column 14, for Duck Creek) from Frick (1985).

Project Wellfield

The project wellfield consists of eight proposed wells at the locations (grid coordinates) listed in Table 2 (see also Figure 1).

TABLE 2
Location Coordinates of Project Wells

Well	Northing	Easting
Proposed Action		
Well 1	4401344.6525	689856.4924
Well 2	4399175.8120	689638.5035
Well 3	4413857.0747	692195.6371
Well 4	4416670.1487	692752.2903
Well 5	4419738.1191	693337.5647
Well 6	4410490.9652	691003.9852
Well 7	4407677.4845	690556.2981
Well 8	4405261.0926	690295.4449
Alternative 1		
Well 1	4372077.3005	687459.3944
Well 2	4374074.0148	686996.0219
Well 3	4376159.1912	687733.2054
Well 4	4377894.7320	688002.8040
Well 5	4378720.3776	687160.3085
Well 6	4380118.9202	687130.8211
Well 7	4381715.4492	687113.9712
Well 8	4382827.5433	688331.3772

For simulations involving the project wellfield, each well was assigned the pumping value of -74,589 cubic feet per day (387 gpm) for the entire period of simulated time. Note, the negative sign signals pumping to the model; a positive value would signal injection.

Time Steps

Transient simulations involved representing the 40-year period of simulated time through 40 stress periods of 365 days, with 100 time steps per stress period and a multiplier of 1.2 (the ratio of the length of each time step to that of the preceding time step).

Sensitivity Analysis

Extensive sensitivity testing of model input parameter values and analysis of the subsequent results were conducted and documented by Frick (1985). In addition, the effects of the results of the sensitivity analysis on the final calibration of the model were also documented by Frick (1985). Reasonable ranges of input values representing stream flow, aquifer

transmissivity (including both aquifer thickness and hydraulic conductivity), evapotranspiration, recharge, and the northeast boundary condition (i.e., the GHB condition cells representing flow from Steptoe Valley to Goshute Valley). The results of the sensitivity testing at the time the original model was developed are summarized in Table 7 of Frick (1985).

In addition, as discussed above under Principal Assumptions, sensitivity Analysis was conducted on values of aquifer storage coefficient and specific yield.

Model Simulations

Steady-State Comparison with Frick (1985)

The first simulation by the re-created model was of the steady-state flow field with only non-project pumping. For this simulation, the background pumping was set in the re-created model to 20,300 af/year to be consistent with Frick (1985). The resulting water budget components are compared against those from Frick (1985) in Table 3.

TABLE 3
Simulated Water Budget Components: Steady-State Steptoe Valley Base Scenario (Background Pumping Only)

Water Budget Component	Frick (1985) Simulation Results (af/year)	Re-Created Model Simulation Results (af/year)
In		
Recharge	83,600	79,390
Stream Leakage	15,300	12,817
Total	**98,900**	**92,207**
Out		
Wells	20,300	20,300
Evapotranspiration	76,200	68,072
Stream Leakage	0	1,199
Head Dependent Boundary (Flow to Goshute Valley)	2,510	2,640
Total	**99,010**	**92,211**

The results indicate that the overall water budget is approximately 7 percent less in the results of the re-created model relative to the budget reported by Frick (1985), but that the budget balances well in both models. One notable point is that the re-created model required some reaches of either (or both) Duck Creek or Steptoe Creek to gain flow from ground water. This is inconsistent with conditions observed in the field and the results produced by Frick (1985). This error directly resulted in the difficulty to match the vertical discretization in the two models. However, the error is not considered significant with respect to the ability of the re-created model to represent reasonably the project wellfield and simulate time-dependent ground water level declines as a result of project pumping.

Transient Simulation Results

For the purpose of determining the magnitude of ground water level declines after 40 years of project pumping for the Proposed Action and Alternative 1, the re-created model was used to simulate three different future pumping scenarios. The first scenario involved the simulation of the base case, which is ground water conditions 40 years into the future in the absence of ground water withdrawals for the proposed project (only non-project ground water pumping of 6,360 af/year was included in the simulation). The resulting ground water budget components from this simulation are summarized in Table 4.

TABLE 4
Simulated Water Budget Components – 40-Year Base Scenario (Background Pumping Only)

Water Budget Component	Re-Created Model Simulation Results (af/year)
In	
Storage	2,840
Recharge	79,390
Stream Leakage	9,923
Total	**92,153**
Out	
Storage	313
Wells	6,360
Evapotranspiration	82,474
Stream Leakage	340
Head dependent Boundary (Flow to Goshute Valley)	2,654
Total	**92,141**

The second scenario was the same as the first, but with the addition of project pumping using the Proposed Action wellfield configuration (40-year simulation of ground water conditions with both project [Proposed Action] and non-project [No Action Alternative] pumping). The resulting ground water budget components from this simulation are summarized in Table 5.

TABLE 5
Simulated Water Budget Components—40-Year Combined Pumping Scenario (Background and Project Pumping)—Proposed Action Wellfield Configuration

Water Budget Component	Re-Created Model Simulation Results (af/year)
In	
Storage	3,572
Recharge	79,390
Stream Leakage	9,924
Total	**92,886**

TABLE 5
Simulated Water Budget Components—40-Year Combined Pumping Scenario (Background and Project Pumping)—Proposed Action Wellfield Configuration

Water Budget Component	Re-Created Model Simulation Results (af/year)
Out	
Storage	338
Wells	11,360
Evapotranspiration	78,183
Stream Leakage	342
Head dependent Boundary (Flow to Goshute Valley)	2,654
Total	**92,877**

The last scenario was the same as the first, but with the addition of project pumping using the Alternative 1 wellfield configuration (40-year simulation of ground water conditions with both project [Alternative 1] and non-project [No Action Alternative] pumping). The resulting ground water budget components from this simulation are summarized in Table 6.

TABLE 6
Simulated Water Budget Components—40-Year Combined Pumping Scenario (Background and Project Pumping)—Alternative 1 Wellfield Configuration

Water Budget Component	Re-Created Model Simulation Results (af/year)
In	
Storage	3,061
Recharge	79,390
Stream Leakage	9,865
Total	**92,316**
Out	
Storage	340
Wells	11,360
Evapotranspiration	77,638
Stream Leakage	312
Head dependent Boundary (Flow to Goshute Valley)	2,654
Total	**92,303**

The difference in hydraulic head between the base case scenario and Proposed Action and Alternative 1 represents the change in ground water levels caused solely by project

pumping (8 project wells pumping 625 gpm continuously for 40 years). The project-induced drawdown in Layer 1 (shallow unconfined aquifer) under the Proposed Action is presented in Figure 15, and the results for Layer 2 (deeper confined ground water) under the Proposed Action are presented in Figure 16. The project-induced drawdown in Layer 1 (shallow unconfined aquifer) under Alternative 1 is presented in Figure 17, and the results for Layer 2 (deeper confined ground water) under Alternative 1 are presented in Figure 18.

The results indicate a project-induced drawdown for the Proposed Action of up to 8 feet in Layer 1 and 8.5 feet in Layer 2. The results for Alternative 1 indicate a project-induced drawdown of up to 2.5 feet in Layer 1 and Layer 2. The significance of these drawdowns with respect to other water resources features (creeks, lakes, and springs) and other (non-project) points of ground water diversion is discussed in the WPES EIS.

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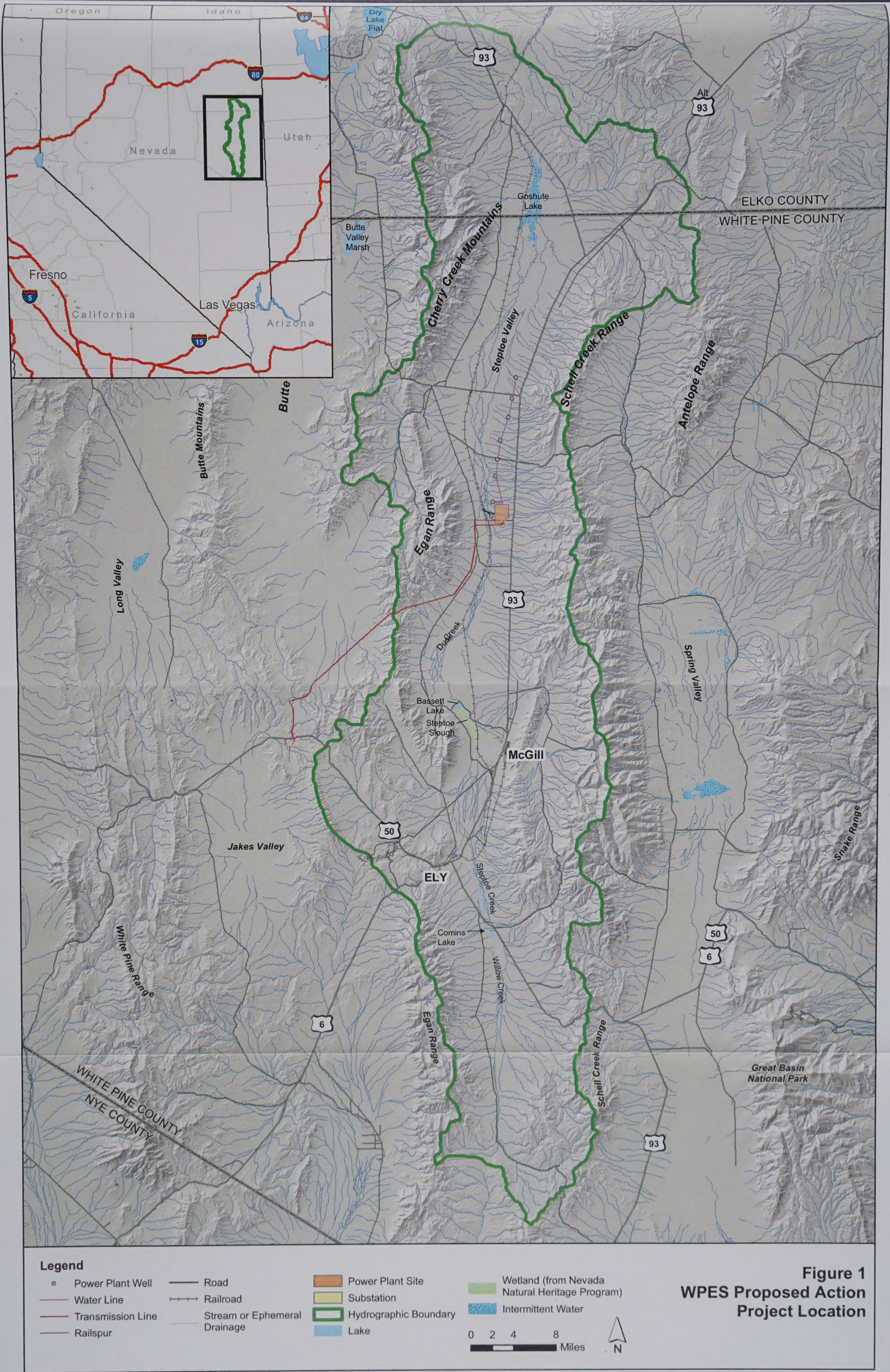

Figure 1
WPES Proposed Action Project Location

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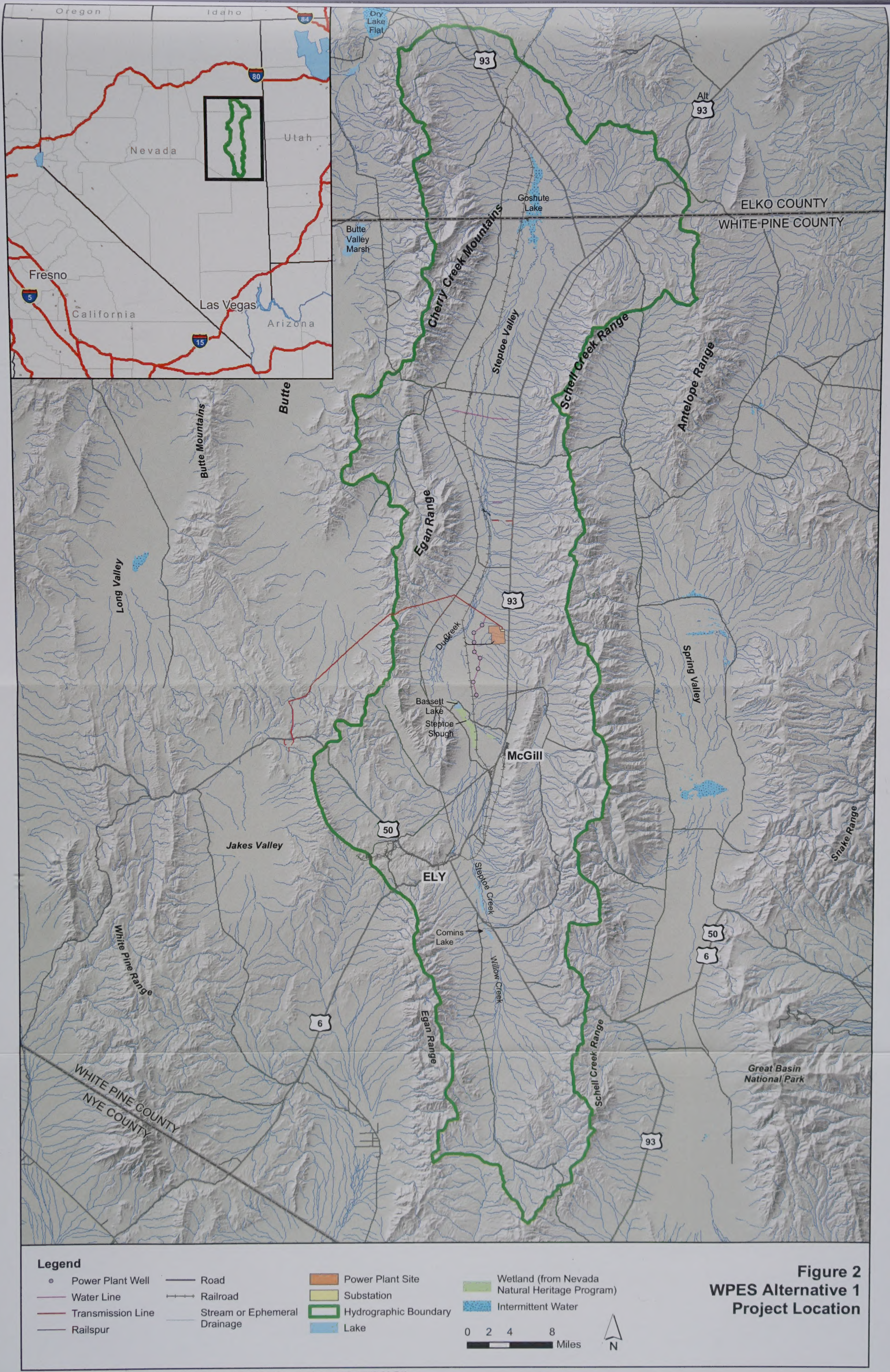

Figure 2
WPES Alternative 1
Project Location

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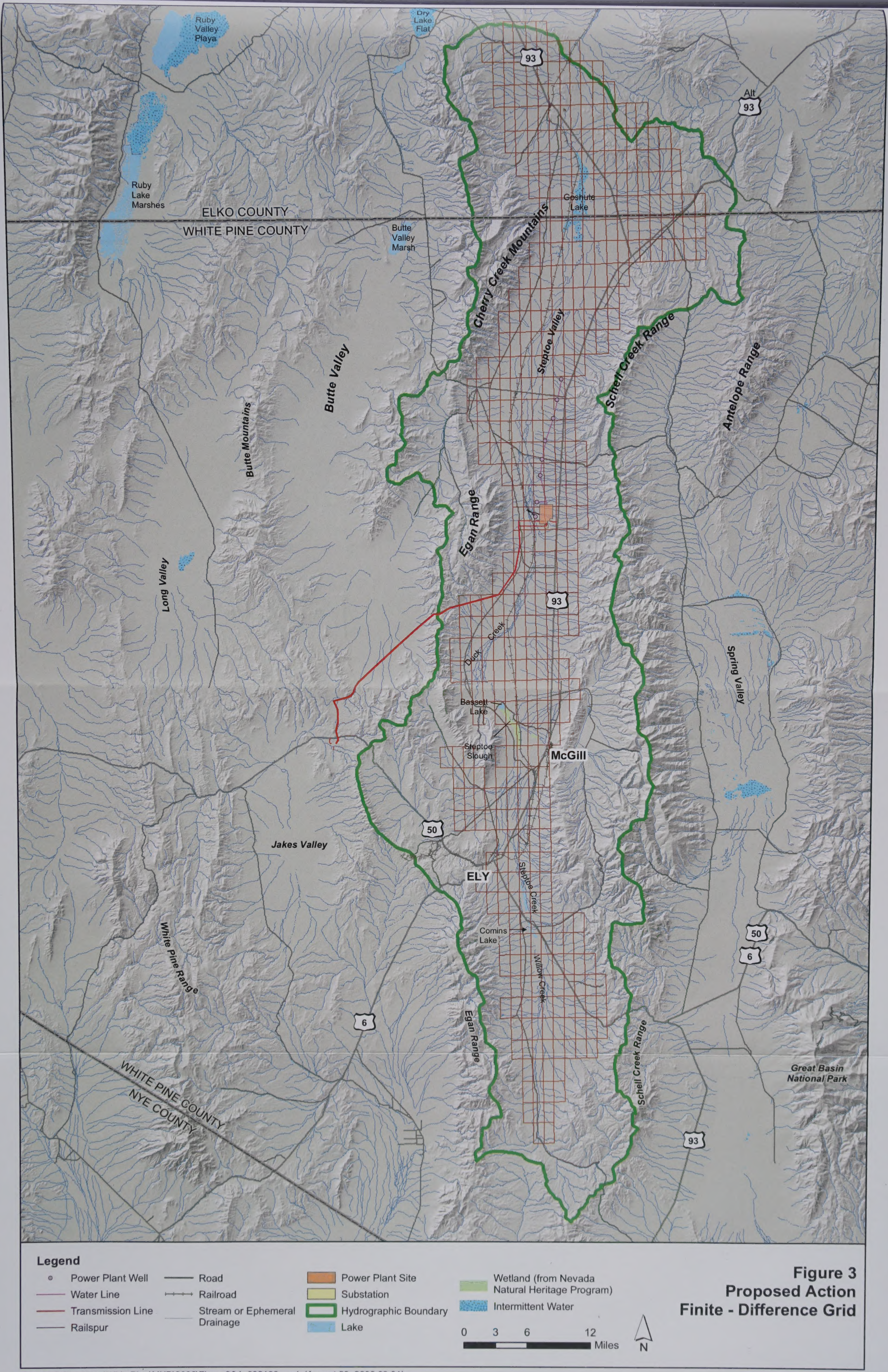

Figure 3
Proposed Action
Finite - Difference Grid

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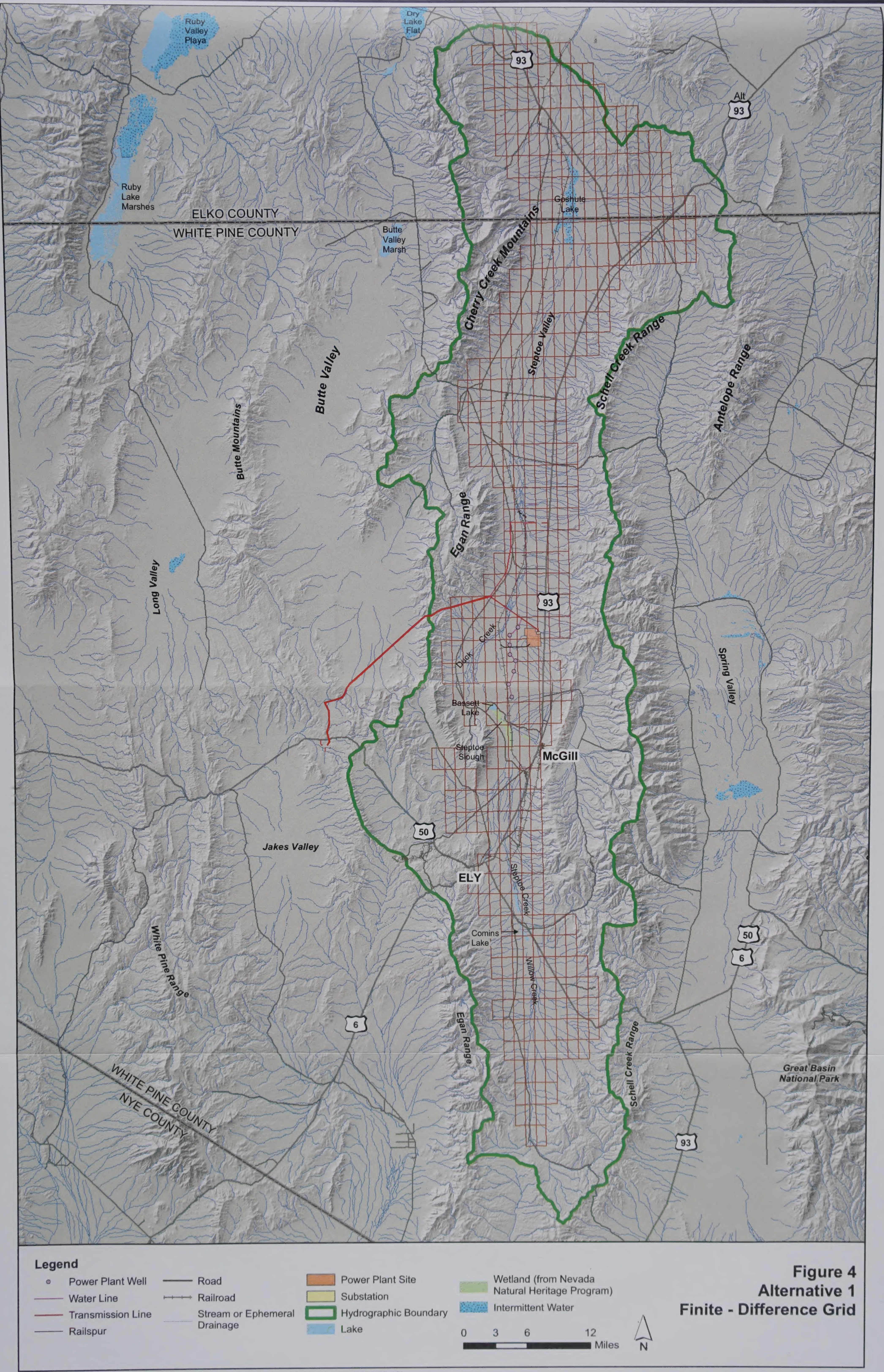

Figure 4
Alternative 1
Finite - Difference Grid

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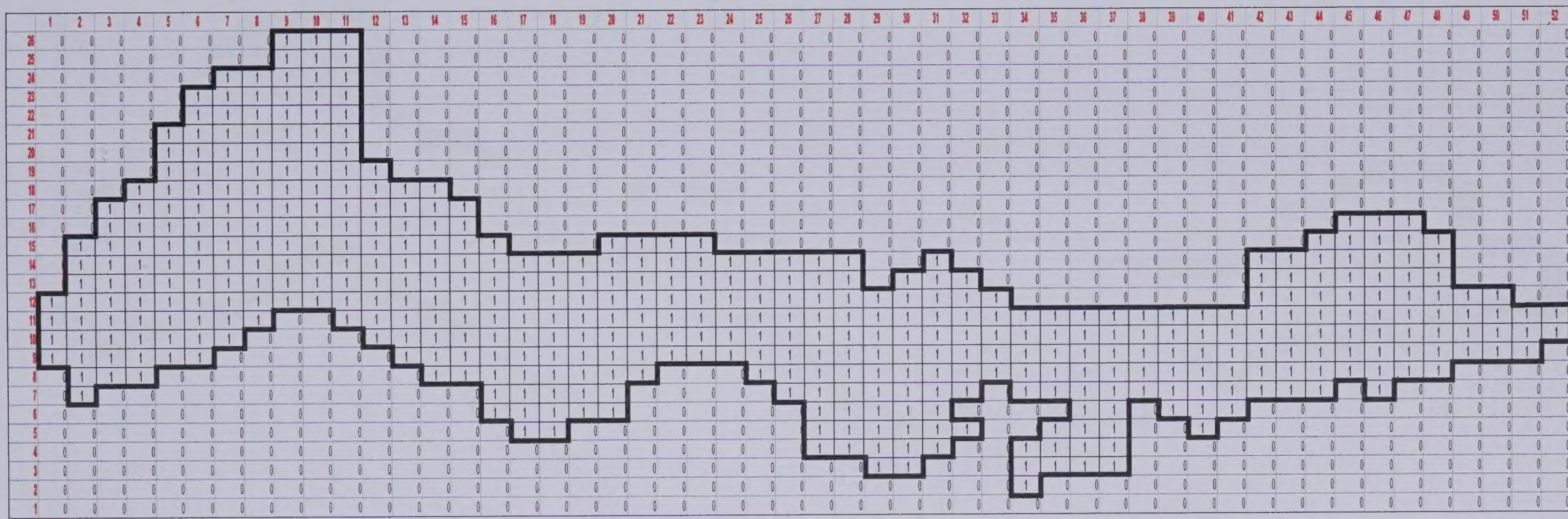

Figure 5
Finite-difference grid (layers 1 & 2)

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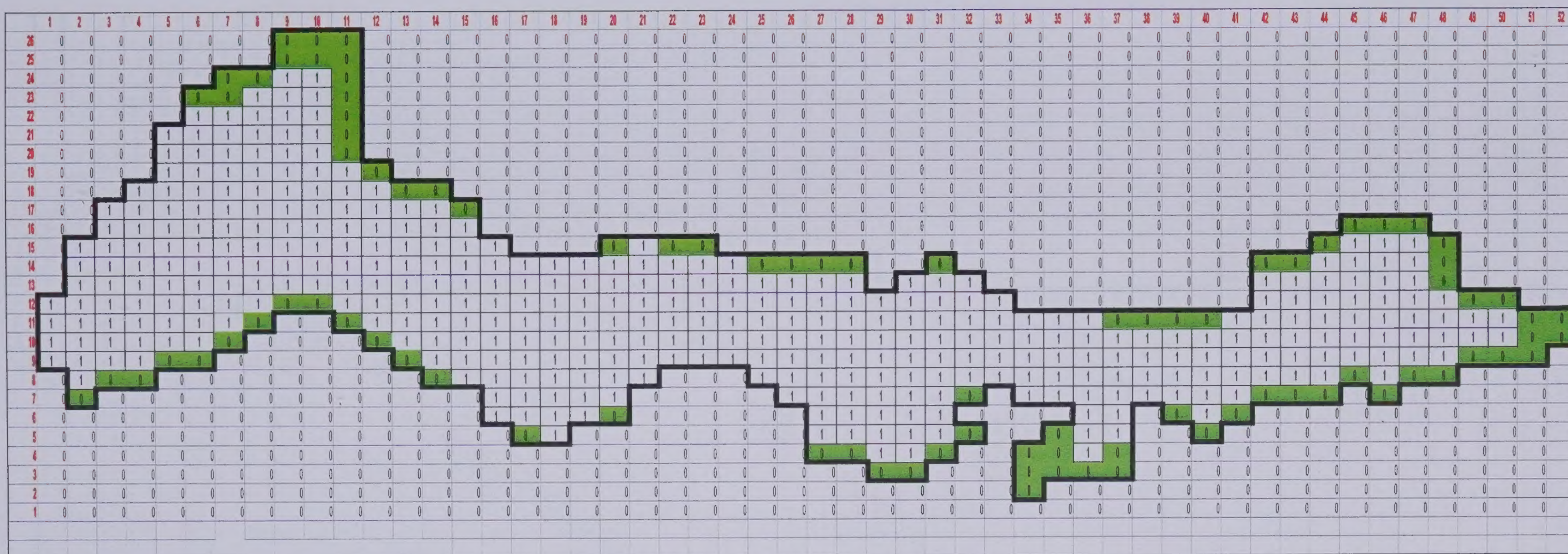
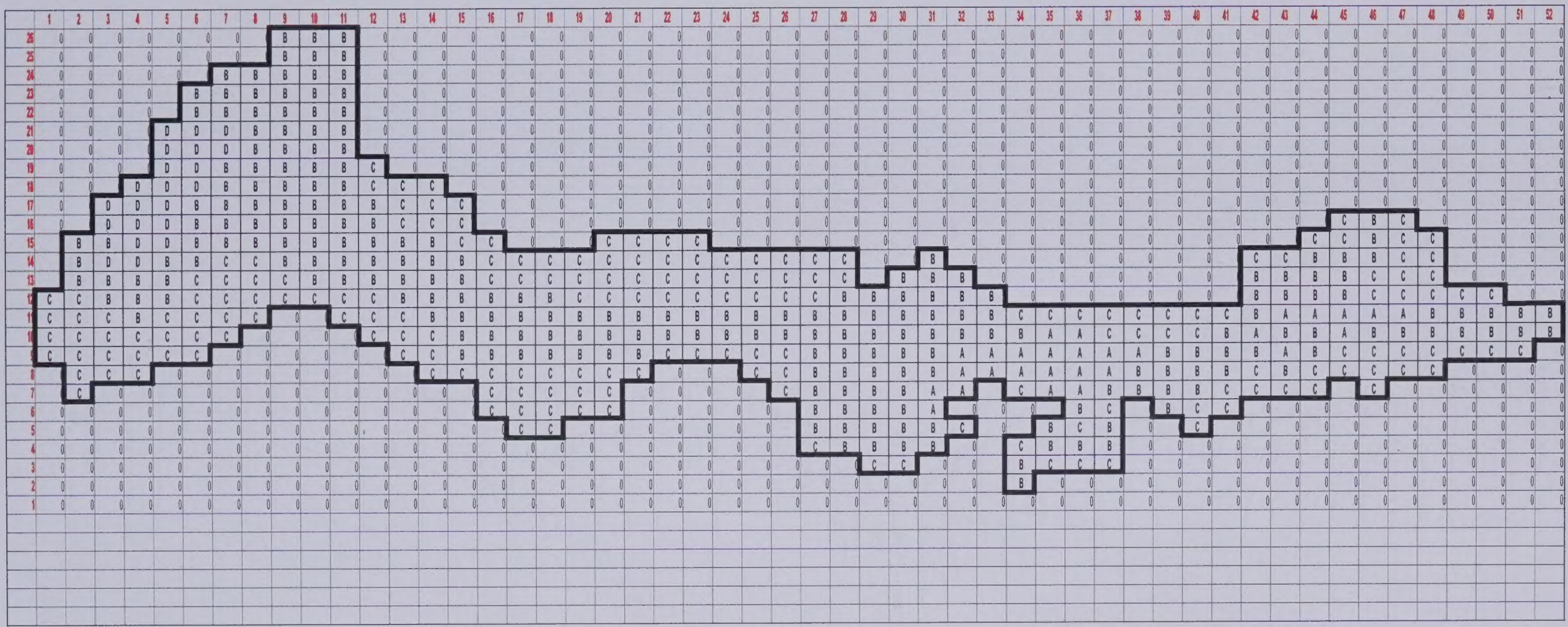


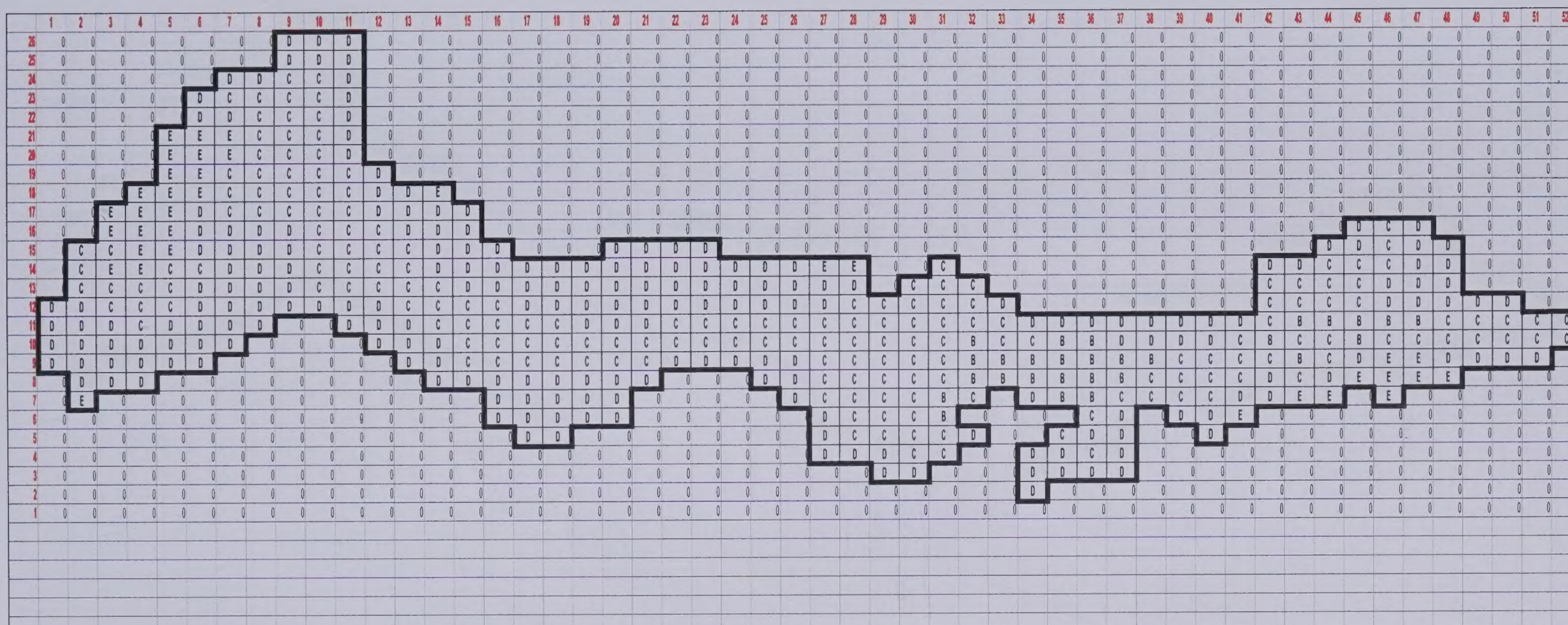
Cell in Layer 1 and 2 that is eliminated in Layer 3

Figure 6
Finite-difference grid (layer 3)



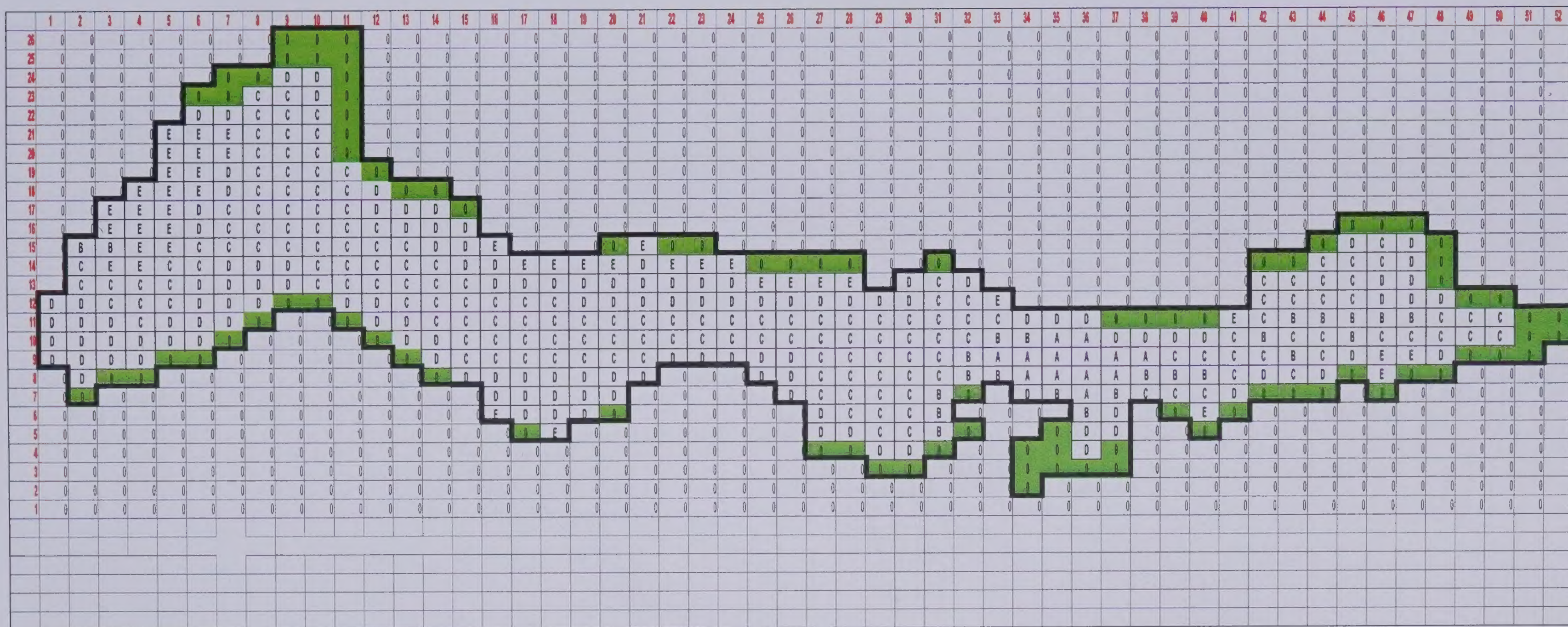
A = 1 to 5E-3 ft/sec
B = 1 to 9E-4 ft/sec
C = 1 to 9E-5 ft/sec
D = 1 to 9E-6 ft/sec

Figure 7
Hydraulic conductivity(K) distribution (layer 1)



A = 0.1-0.155 ft2/sec
B = 0.05-0.099 ft2/sec
C = 0.01-0.049 ft/sec
D = 0.001-0.0099 ft2/sec
E = 0.0001-0.0009 ft2/sec

Figure 8
Transmissivity (T) distribution (layer 2)



A = 0.1-0.155 ft2/sec
B = 0.05-0.099 ft/sec
C = 0.01-0.049 ft/sec
D = 0.001-0.0099 ft/sec
E = 0.001-0.009 ft/sec
= Cell in Layer 1 and 2 that is eliminated in Layer 3

Figure 9
Transmissivity (T) distribution (layer 3)

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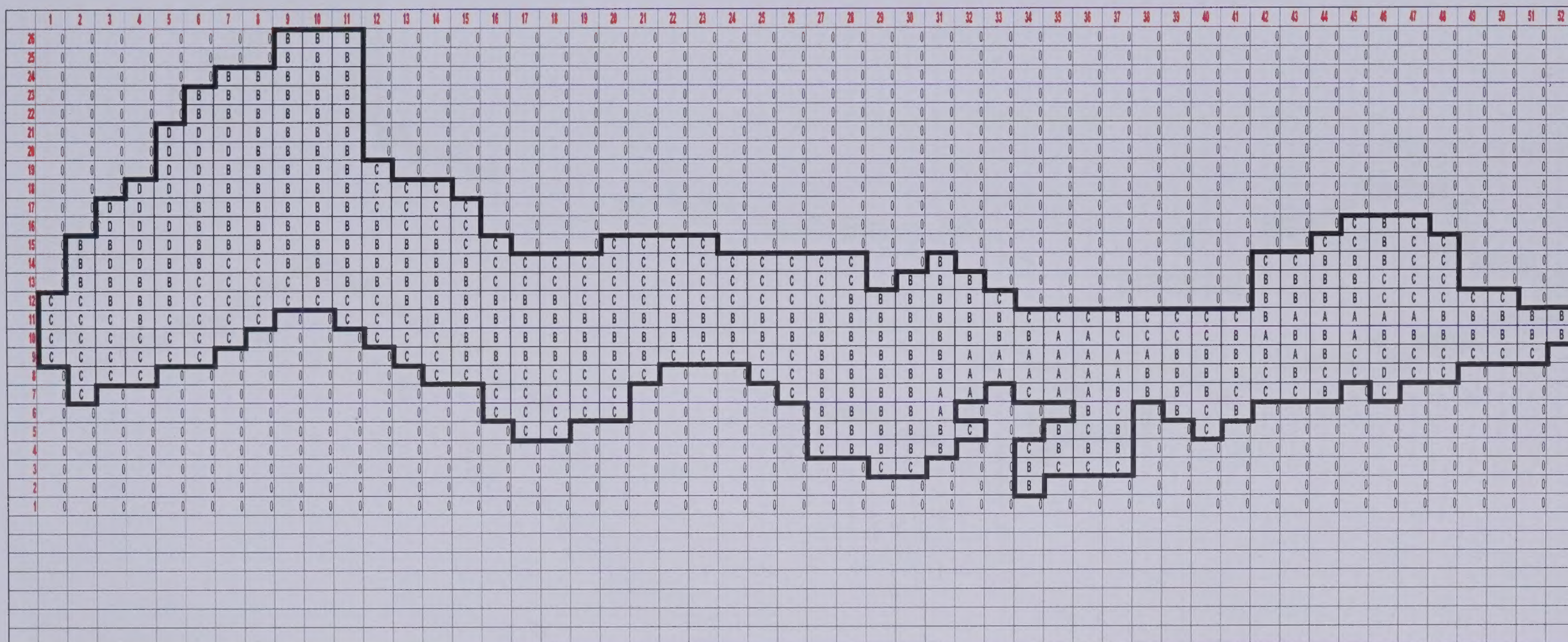

A = 1 to 99E-8 1/sec
B = 1 to 99E-9 1/sec
C = 1 to 99E-10 1/sec
D = 1 to 99E-11 1/sec
E = 1 to 99E-12 1/sec

Figure 10
Leakance distribution between layers 1 & 2

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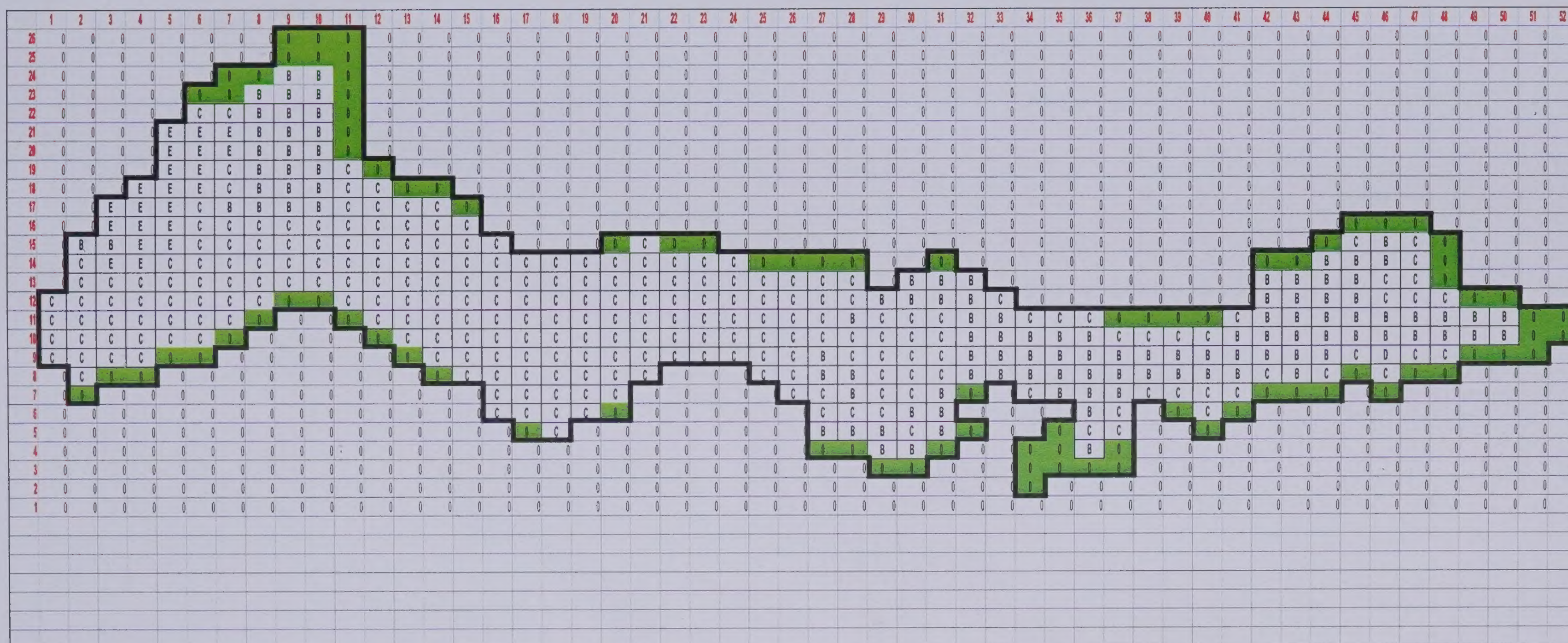
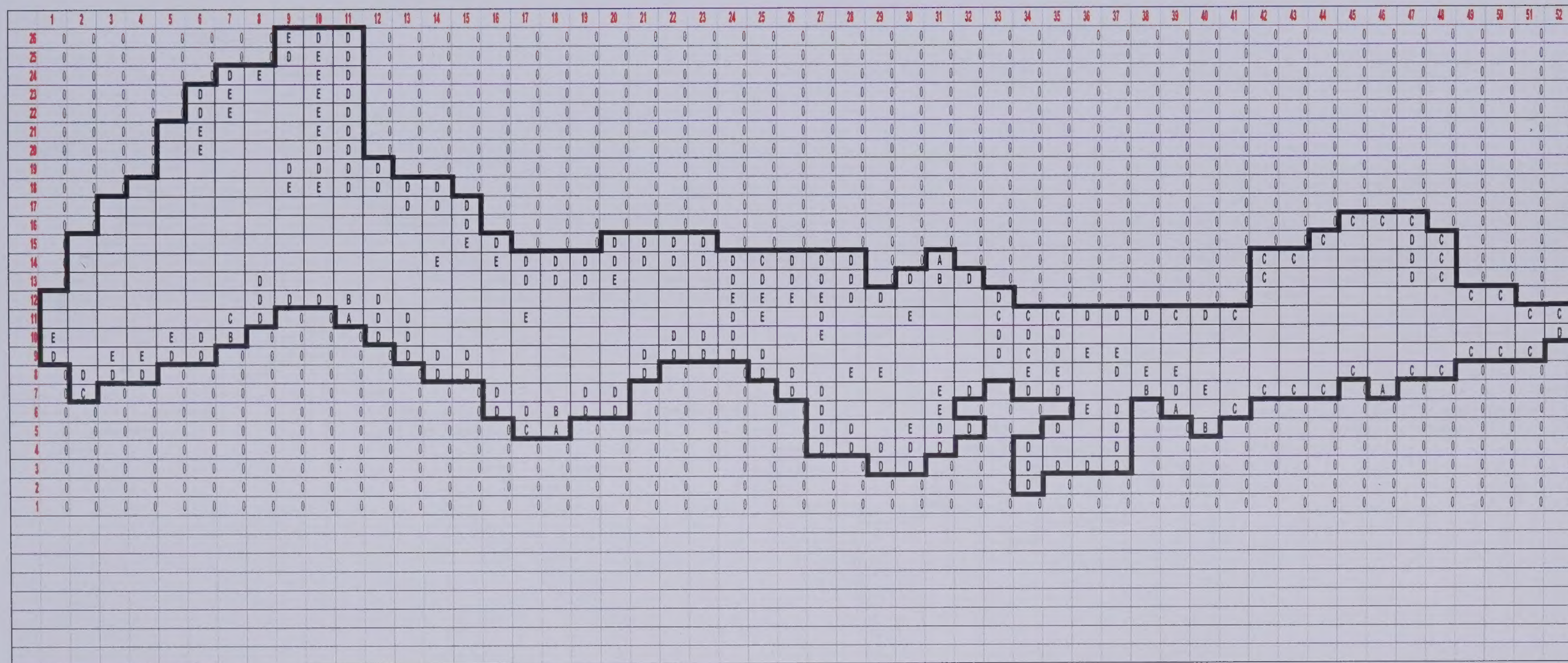


A = 1 to 99E-8 1/sec
B = 1 to 99E-9 1/sec
C = 1 to 99E-10 1/sec
D = 1 to 99E-11 1/sec
E = 1 to 99E-12 1/sec

Figure 11
Leakance distribution between layers 2 & 3



A = 2000-3000 AF/yr
B = 1000-1999 AF/yr
C = 500-999 AF/yr
D = 100-499 AF/yr
E = 100 AF/yr
Blank = 0

Figure 12
Recharge distribution layer 1

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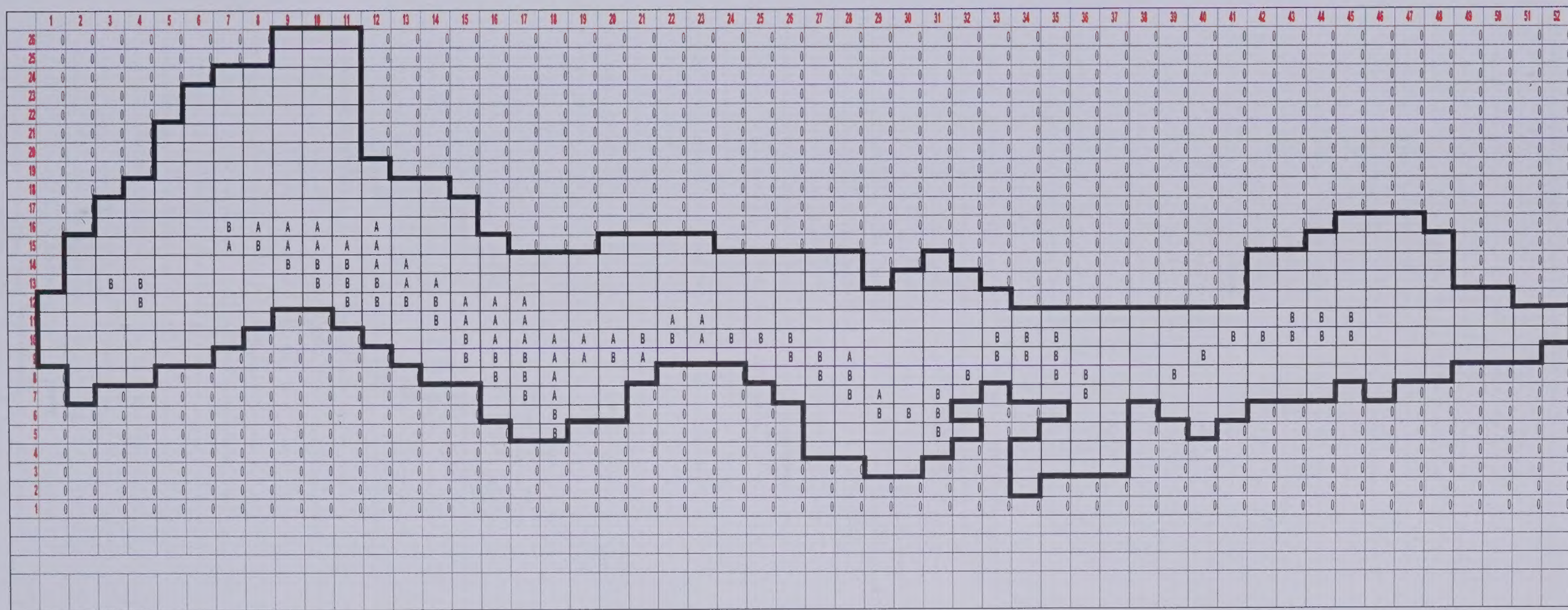

Distribution of evaporation (no values reported)
Blank = 0
A = Steady-state simulation
B = Project pumping simulation

Figure 13
Evapotranspiration cells layer 1

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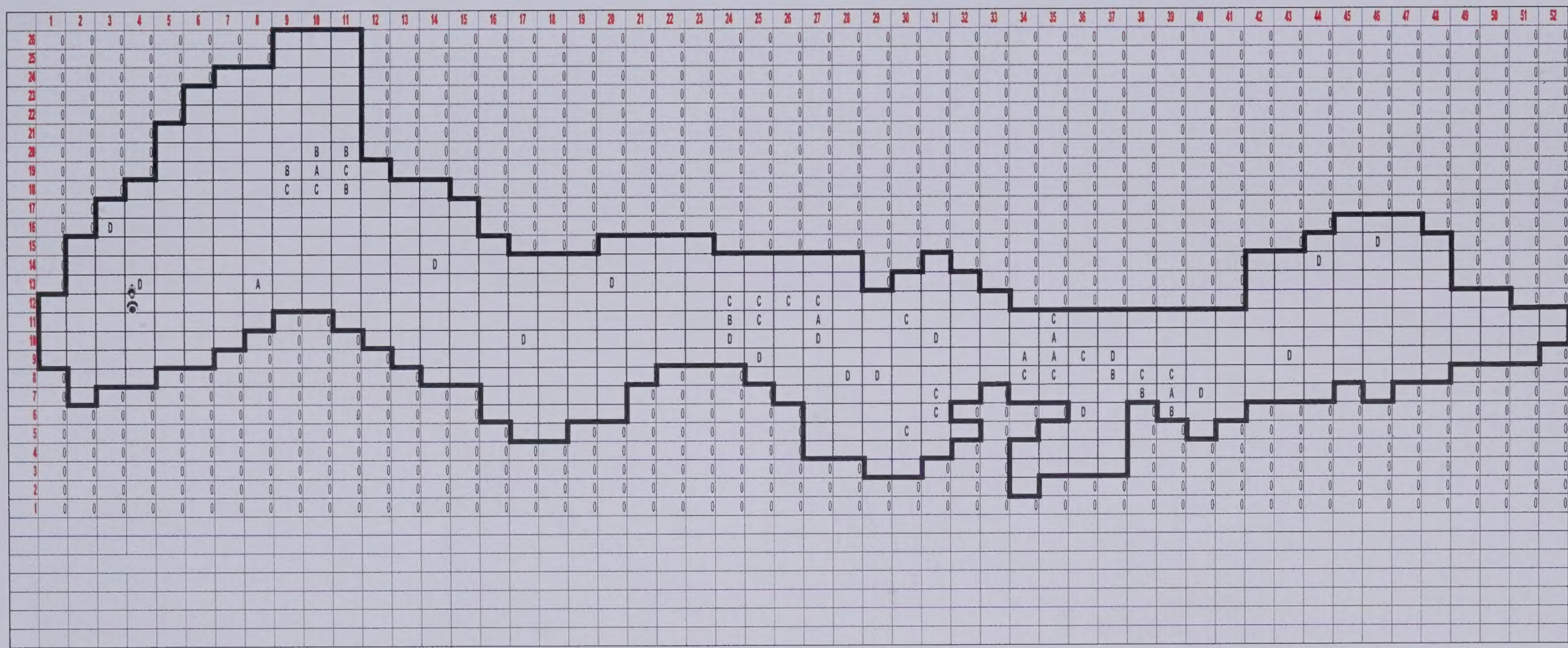
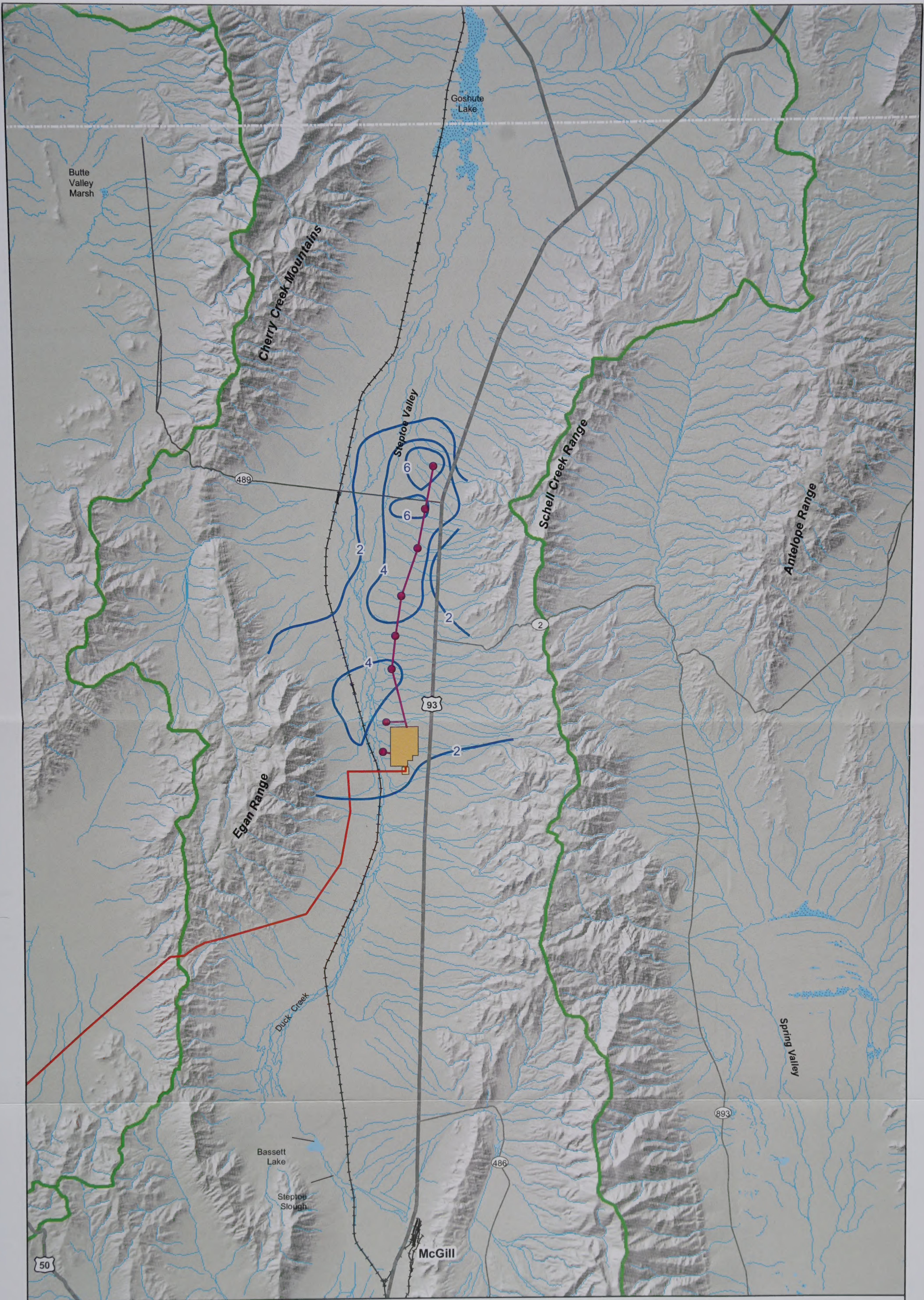


A = 1000-1900 AF/yr
B = 500-999 AF/yr
C = 100-499 AF/yr
D = 100 AF/yr
Blank = 0

Figure 14
Background pumping distribution



Legend

- Groundwater Drawdown Contours
- Proposed Well Field
- Proposed Site
- Substation
- Transmission Line
- Water Line
- Hydrographic Boundary
- Lake
- Intermittent Water
- Railroad

N

0 1 2 4 Miles

Figure 15
White Pine Energy Station
Proposed Action
Potential Project Induced
Ground Water Level Declines
Model Layer 1

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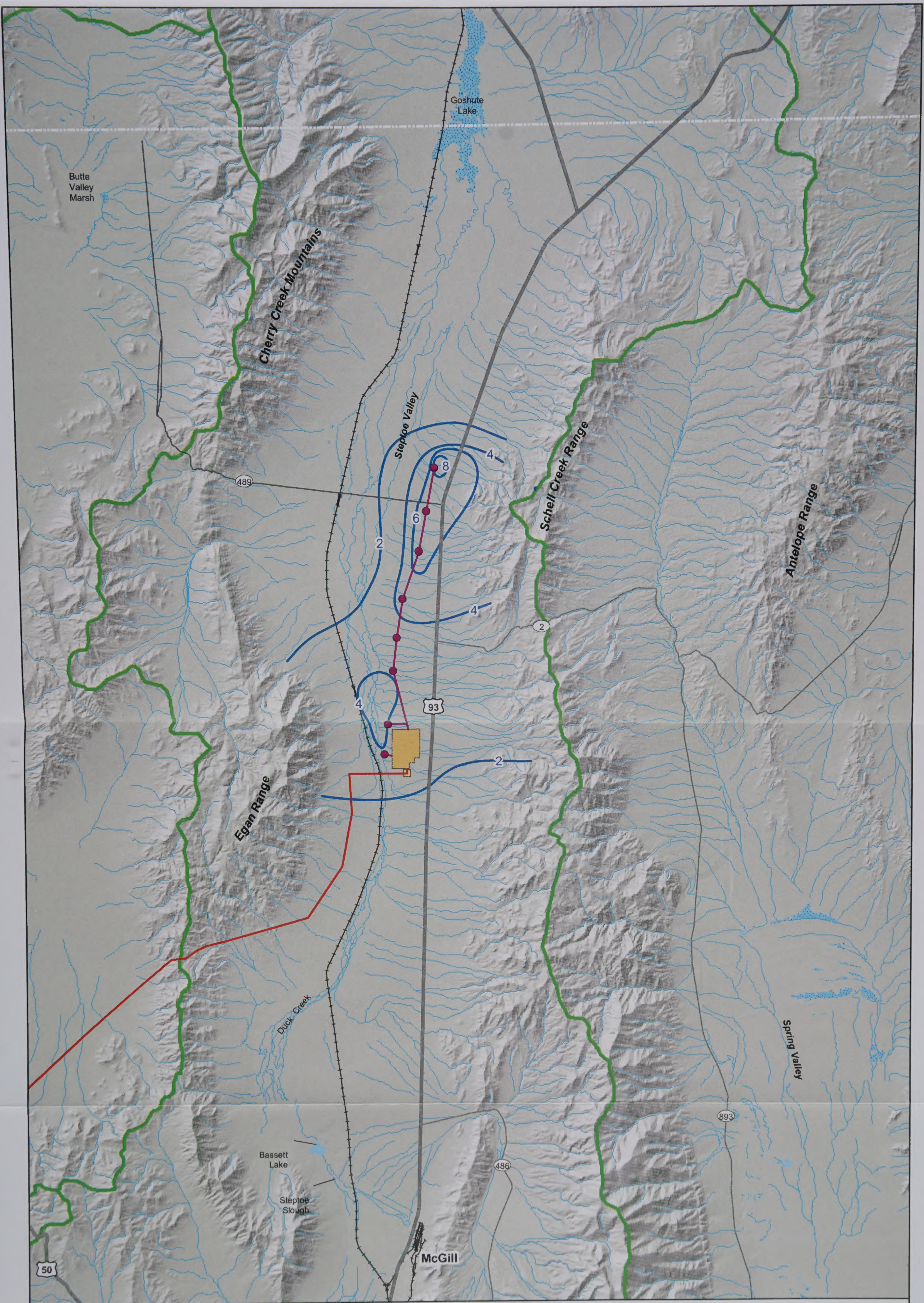

Legend

- Groundwater Drawdown Contours
- Proposed Well Field
- Proposed Site
- Substation
- Transmission Line
- Water Line
- Hydrographic Boundary
- Lake
- Intermittent Water
- Railroad

N

0 1 2 4 Miles

Figure 16
White Pine Energy Station
Proposed Action
Potential Project Induced
Ground Water Level Declines
Model Layer 2

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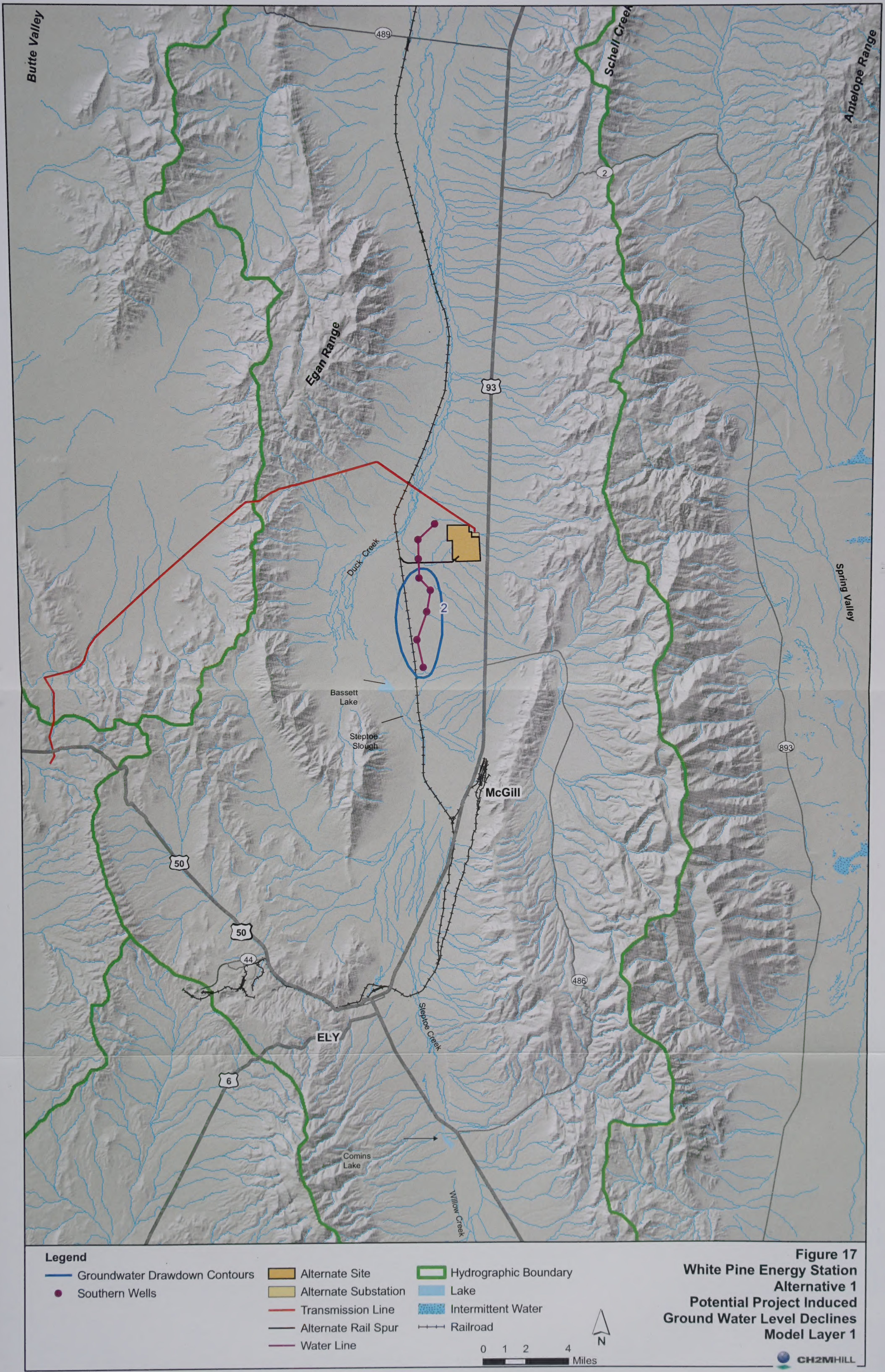

Figure 17
White Pine Energy Station
Alternative 1
Potential Project Induced
Ground Water Level Declines
Model Layer 1

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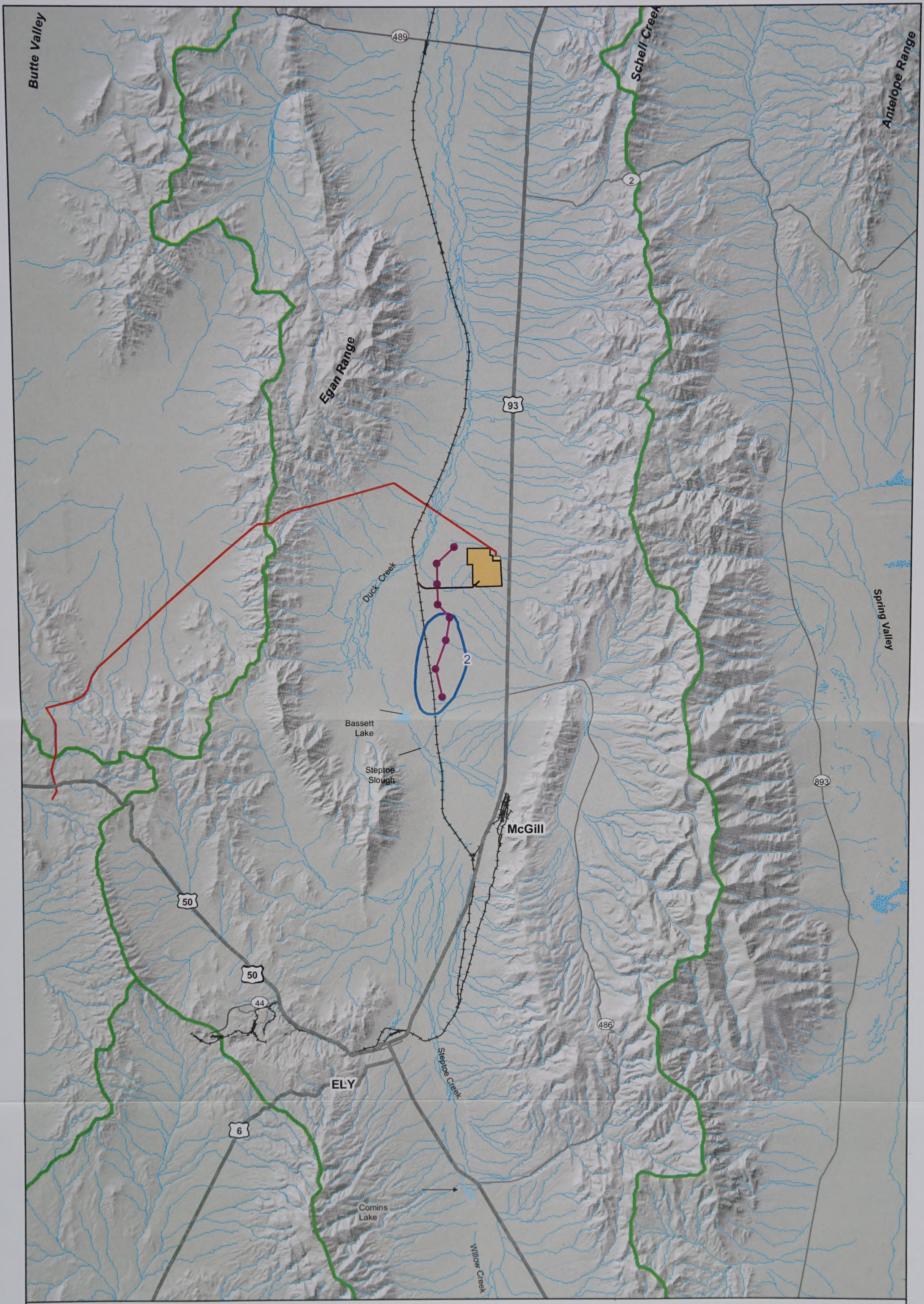

Legend

- Groundwater Drawdown Contours
- Southern Wells
- Alternate Site
- Alternate Substation
- Transmission Line
- Alternate Rail Spur
- Water Line
- Hydrographic Boundary
- Lake
- Intermittent Water
- Railroad

N

0 1 2 4 Miles

Figure 18
White Pine Energy Station
Alternative 1
Potential Project Induced
Ground Water Level Declines
Model Layer 2

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